SECURITIES AND EXCHANGE COMMISSION

FORM 40-F

Annual reports filed by certain Canadian issuers pursuant to Section 15(d) and Rule 15d-4

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EMERA INC

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SIC: **4911** Electric services

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

☐ REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

☒ ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2023 Commission File Number 000-54516

EMERA INCORPORATED
(Exact name of Registrant as specified in its charter)

Nova Scotia, Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

Not applicable
(I.R.S. Employer Identification Number (if applicable))

5151 Terminal Road
Halifax, Nova Scotia, Canada
B3J 1A1
Telephone: (902) 428-6096
(Address and telephone number of Registrant's principal executive offices)

Emera US Finance LP
c/o Corporation Service Company
251 Little Falls Drive
Wilmington, Delaware 19808
Telephone: (302) 636-5401
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act: Not applicable.

Securities registered or to be registered pursuant to Section 12(g) of the Act: Not applicable.

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: Not applicable.

For annual reports, indicate by check mark the information filed with this Form:

☒ Annual information form ☒ Audited annual financial statements

Number of outstanding shares of each of the issuer's classes of
capital or common stock as of December 31, 2023:

284,117,511 Common Shares
4,866,814 Series A First Preferred Shares
1,133,186 Series B First Preferred Shares
10,000,000 Series C First Preferred Shares
5,000,000 Series E First Preferred Shares
8,000,000 Series F First Preferred Shares
12,000,000 Series H First Preferred Shares
8,000,000 Series J First Preferred Shares
9,000,000 Series L First Preferred Shares

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☐ No ☒

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☒ No ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to § 240.10D-1(b). ☐

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares is financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications regarding controls and procedures. See Exhibits 99.5 and 99.6.

(b) Evaluation of disclosure controls and procedures. As of December 31, 2023, an evaluation of the effectiveness of the Registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the United States Securities Exchange Act of 1934, as amended (the "Exchange Act")), was carried out by the Registrant's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"). Based on that evaluation, the CEO and CFO have concluded that as of such date the Registrant's disclosure controls and procedures are effective to provide a reasonable level of assurance that information required to be disclosed by the Registrant in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission's (the "Commission") rules and forms.

It should be noted that while the CEO and CFO believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect the disclosure controls and procedures or internal control over financial reporting to be capable of preventing all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Management's annual report on internal control over financial reporting. The Registrant's management is responsible for establishing and maintaining adequate internal control over financial reporting. The Registrant'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. The Registrant's management, including the CEO and CFO, evaluated the design and effectiveness of the Registrant's internal control over financial reporting as at December 31, 2023 and concluded that the Registrant's internal control over financial reporting is effective as at December 31, 2023.

(d) Attestation report of the registered public accounting firm. This annual report does not include an attestation report of the Registrant's registered public accounting firm regarding internal control over financial reporting.

(e) Changes in internal control over financial reporting. There were no changes in the Registrant's internal control over financial reporting during the fiscal year ended December 31, 2023, that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

Audit Committee Financial Expert. The Registrant's board of directors (the "Board") has determined that five audit committee financial experts serve on its Audit Committee. The audit committee financial experts are Paula Y. Gold-Williams, Kent M. Harvey, B. Lynn Loewen, Ian E. Robertson, and Andrea S. Rosen. The Board has determined that Paula Y. Gold-Williams, Kent M. Harvey, B. Lynn Loewen, Ian E. Robertson, and Andrea S. Rosen are independent within the meaning of the listing standards of the New York Stock Exchange. Information concerning the relevant experience of Paula Y. Gold-Williams, Kent M. Harvey, B. Lynn Loewen, Ian E. Robertson, and Andrea S. Rosen is included in their biographical information contained in the Registrant's Annual Information Form for the fiscal year ended December 31, 2023, filed as Exhibit 99.1 hereto (the "Annual Information Form"). The Commission has indicated that the designation of a person as an audit committee financial expert does not make such person an "expert" for any purpose, impose any duties, obligations or liability on such person that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation, or affect the duties, obligations or liability of any other member of the audit committee or board of directors.

Code of Ethics. The Emera Code of Conduct was revised and became effective on October 1, 2023 (the "Code") and applies to all directors, officers and employees of the Registrant, including the CEO and CFO. Since the adoption of the Code, there have not been any waivers, including implied waivers, from any provision of the Code. A copy of the Code can be found on Emera's internet website at the following address: https://www.emera.com/about-us/who-we-are/code-of-conduct.

The Code was furnished to the Commission on November 24, 2023 as Exhibit 99.1 to a report on Form 6-K and is incorporated by reference herein as Exhibit 99.9.

Principal Accountant Fees and Services. The information provided under the headings "Audit Committee—Audit and Non-Audit Services Pre-Approval Process" and "Audit Committee—Auditors' Fees" contained in the Registrant's Annual Information Form. The Registrant's Audit Committee approved all of the Audit-Related and Tax services provided by Ernst & Young LLP in 2023 and none were approved pursuant to the de minimis exception provided by Section (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

In connection with the Commission's adoption of amendments to finalize the implementation of disclosure and submission requirements on December 2, 2021, pursuant to Release No. 34-93701, the Registrant hereby affirms that Ernst & Young LLP (PCAOB ID: 1263) delivered an audit opinion relating to the Registrant's Financial Statements (as defined below) contained in the Annual Information Form, and such audit opinion was issued in Halifax, Nova Scotia, Canada.

Liquidity and Capital Resources

The information provided under the headings (a) "Off-Balance Sheet Arrangements" and (b) "Contractual Obligations" contained in the Registrant's Management's Discussion and Analysis dated February 26, 2024 for the year ended December 31, 2023, filed as Exhibit 99.2 hereto (the "MD&A") and with respect to clause (a) the information provided at note 27 ("D. Guarantees and Letters of Credit") and note 32 ("Variable Interest Entities"), and with respect to clause (b) note 27 ("A. Commitments") and note 25 ("Long-Term Debt"), to the Audited Consolidated Financial Statements as at and for the years ended December 31, 2023 and December 31, 2022, filed as Exhibit 99.3 hereto (the "Financial Statements"), are incorporated by reference herein.

Identification of the Audit Committee. The information provided under the heading "Audit Committee" contained in the Annual Information Form is incorporated by reference herein.

Mine Safety Disclosure. Neither the Registrant nor any of its subsidiaries is the "operator" of any "coal or other mine", as those terms are defined in section 3 of the Federal Mine Safety and Health Act of 1977 (30 U.S.C. 802), that is subject to the provisions of such Act (30 U.S.C. 801 et seq.). Therefore, the provisions of Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 16 of General Instruction B to Form 40-F requiring disclosure concerning mine safety violations and other regulatory matters do not apply to the Registrant or any of its subsidiaries.

EXHIBIT INDEX

Exhibit Number	Description
99.1	2023 Annual Information Form dated February 26, 2024 for the fiscal year ended December 31, 2023
99.2	Management's Discussion and Analysis dated February 26, 2024 for the year ended December 31, 2023
99.3	Audited Consolidated Financial Statements as at and for the years ended December 31, 2023 and December 31, 2022
99.4	Consent of Independent Registered Public Accounting Firm
99.5	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the U.S. Securities Exchange Act of 1934, as amended
99.6	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the U.S. Securities Exchange Act of 1934, as amended

99.7	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.8	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.9	Emera Code of Conduct (as revised on October 1, 2023) (incorporated by reference to Emera Incorporated’s Form 6-K, furnished to the Commission on November 24, 2023)
101	Interactive Data File (formatted as Inline XBRL)
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of a Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

DATED this 26th day of February, 2024.

EMERA INCORPORATED

By: /s/ Scott C. Balfour
Name: Scott C. Balfour
Title: President & Chief Executive Officer

Exhibit 99.1

Emera Incorporated
Annual Information Form

For the year ended December 31, 2023

February 26, 2024

ANNUAL INFORMATION FORM

For the year ended December 31, 2023
Dated: February 26, 2024

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form ("AIF") is given at or for the year ended December 31, 2023. Amounts are expressed in Canadian dollars unless otherwise indicated. All financial information presented in millions of Canadian dollars is rounded to the nearest million unless otherwise stated. Unless otherwise indicated, all financial information is presented in accordance with United States' generally accepted accounting principles ("USGAAP"). Emera Incorporated ("Emera" or "the Company") uses Adjusted Net Income Attributable to Common Shareholders ("adjusted net income") as a financial performance measure, which is not a defined financial measure according to USGAAP and does not have standardized meanings prescribed by USGAAP. For further information on the non-GAAP financial measure, adjusted net income, including a full description of the measure and a reconciliation to the nearest USGAAP measure, please refer to the Company's MD&A section entitled "Non-GAAP Financial Measures and Ratios", which is incorporated herein by reference, a copy of which is available electronically under Emera's profile on SEDAR+ at www.sedarplus.ca.

Certain capitalized terms used herein, and not otherwise defined herein, are defined under "Definitions of Certain Terms", attached to this AIF as Appendix "A". References to "including", "include", or "includes" means "including (or includes) but is not limited to" and shall not be construed to limit any general statement preceding it to the specific or similar items or matters immediately following it.

This AIF provides material information about the business and operations of Emera. The "Enterprise Risk and Risk Management" section of the Company's MD&A is incorporated herein by reference and can be found on SEDAR+ at www.sedarplus.ca.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

This AIF, including the documents incorporated herein by reference, contains "forward-looking information" and "forward-looking statements" within the meaning of applicable securities laws (collectively, "forward-looking information"). 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. References to "Emera" in this section include references to the subsidiaries of Emera.

The forward-looking information in this AIF, including the documents incorporated herein by reference, includes statements which reflect the current view of Emera's management with respect to Emera's objectives, plans, financial and operating performance, carbon dioxide emissions reduction goals, business prospects and opportunities. 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(s) at which, such events, performance or results will be achieved. All such forward-looking information in this AIF is provided pursuant to safe harbour provisions contained in applicable securities laws.

The forward-looking information in this AIF, including the documents incorporated herein by reference, includes, but is not limited to, statements regarding: Emera's revenue, earnings and cash flow; the growth and diversification of Emera's business and earnings base; future annual net income and dividend growth; expansion of Emera's business; the expected compliance by Emera with the regulation of its operations; the expected timing of regulatory decisions; forecasted capital investments; the nature, timing and costs associated with certain capital projects; the expected impact on Emera of challenges in the global economy; estimated energy consumption rates; expectations related to annual operating cash flows; the expectation that Emera will continue to have reasonable access to capital in the near to medium term; expected debt maturities, repayments and renewals; expectations about increases in interest expense and/or fees associated with debt securities and credit facilities; no material adverse credit rating actions expected in the near term; the successful development of relationships with various stakeholders, the impact of currency fluctuations; expected changes in electricity rates; and the impacts of planned investment by the industry of gas transportation infrastructure within the United States.

The forecasts and projections that make up the forward-looking information are based on reasonable assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather or global climate change, other acts of nature or other major events; seasonal weather patterns remaining stable; no significant cyber or physical attacks or disruptions to Emera' s systems; the continued ability to maintain transmission and distribution systems to ensure their continued performance; continued investment in solar, wind and hydro generation; continued natural gas activity; no severe and/or prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and commodity prices; no significant variability in interest rates; expectations regarding the nature, timing and costs of capital investments of Emera and its subsidiaries; expectations regarding rate base growth; the continued competitiveness of electricity pricing when compared with other alternative sources of energy; the continued availability of commodity supply; the absence of significant changes in government energy plans and environmental laws and regulations that may materially affect Emera' s operations and cash flows; maintenance of adequate insurance coverage; the ability to obtain and maintain licenses and permits; no material decrease in market energy sales prices; favourable labour relations; and sufficient human resources to deliver service and execute Emera' s capital investment plan.

The forward-looking information 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, but are not limited to: regulatory and political risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; changes in credit ratings; future dividend growth; timing and costs associated with certain capital investments; expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; country risks; supply chain risk; environmental risks; foreign exchange (“FX”); regulatory and government decisions, including changes to environmental legislation, 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; 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 AIF and in the documents incorporated herein by reference 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.

CORPORATE STRUCTURE

Name and Incorporation

Emera was incorporated on July 23, 1998 pursuant to the *Companies Act* (Nova Scotia). The Reorganization Act and the Privatization Act require the Company' s Articles of Association (the “Articles”) to contain provisions specifying that the head office and the principal executive offices of the Company are to be situated in the Province of Nova Scotia. The current address of the Company' s registered office, head office and principal executive offices is Emera Place, 5151 Terminal Road, Halifax, Nova Scotia, Canada, B3J 1A1.

Amended Articles of Association

On April 12, 2019, amendments to the Privatization Act and the Reorganization Act were enacted, removing the legislative restriction preventing non-Canadian residents from holding more than 25 per cent of Emera voting shares, in aggregate. These legislative amendments did not alter the existing 15 per cent individual share ownership restriction, as described below in the section entitled "Capital Structure – Share Ownership Restrictions". The Board approved amendments to the Company's Articles and on July 11, 2019, shareholders passed a special resolution to amend the Articles to remove this non-Canadian resident ownership restriction. For more information on these amendments to the Articles, please refer to Emera's Management Information Circular dated May 31, 2019 distributed in connection with a special meeting of shareholders held on July 11, 2019, a copy of which is available electronically under Emera's profile on SEDAR+ at www.sedarplus.ca.

Intercorporate Relationships

The following table sets forth the relationships among the Company and its principal subsidiaries, the percentage of votes attaching to all voting securities of its respective subsidiaries beneficially owned, or controlled or directed, directly or indirectly, by the Company, as well as their respective jurisdictions of incorporation, continuance, formation or organization. This table excludes certain subsidiaries, the assets and revenues of which did not individually exceed 10 per cent, or in the aggregate exceed 20 per cent, of the total consolidated assets or total consolidated revenues of the Company as at December 31, 2023.

Subsidiaries	Percentage Ownership (%)	Jurisdiction
Tampa Electric Company[1]	100	Florida
Nova Scotia Power	100	Nova Scotia
Peoples Gas System[1]	100	Florida
New Mexico Gas Company	100	Delaware

(1) Tampa Electric Company has historically included both its regulated electric and gas utilities, namely the Tampa Electric Division and the Peoples Gas System Division. Effective January 1, 2023, PGS ceased to be a division of TEC and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System, Inc. (existing under the laws of the State of Florida, and a wholly-owned direct subsidiary of TECO Gas Operations, Inc.

INTRODUCTION

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

The majority of Emera's investments in rate-regulated businesses are located in Florida with other investments in Nova Scotia, New Mexico and the Caribbean. Emera's portfolio of regulated utilities provides reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as "rate base"), and the amount of equity in the capital structure and the ROE as approved through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera's capital investment plan is approximately $9 billion over the 2024 through 2026 period with approximately $2 billion of additional potential capital investments over the same period. The capital investment plan and additional potential capital result in an anticipated compound annual rate base growth in the range of approximately 7 per cent to 8 per cent through 2026. The capital investment plan includes significant investments across the portfolio in renewable and cleaner generation, reliability and system integrity investments, infrastructure modernization, infrastructure expansion to meet the needs of new and existing customers, and technologies to better support the business and customer experiences. It is anticipated that approximately 75 per cent of Emera' s $9 billion capital investment plan over the 2024 through 2026 period will be made in Florida.

Emera' s capital investment plan is being funded primarily through internally generated cash flows, debt raised at the operating company level consistent with regulated capital structures, equity, and select asset sales. Generally, equity requirements in support of the Company' s capital investment plan are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera' s DRIP and ATM Program. Maintaining investment-grade credit ratings is a priority of the Company.

Emera has provided annual dividend growth guidance of four to five per cent through 2026. The Company targets a long-term dividend payout ratio of adjusted net income of 70 to 75 per cent and, while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time. For further information on the non-GAAP measure "Dividend Payout Ratio of Adjusted Net Income", refer to the "Non-GAAP Financial Measures and Ratios" section of the MD&A, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

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

Energy markets worldwide are experiencing significant change and Emera is well-positioned to continue to respond to shifting customer demands and meet the challenges of digitization, decarbonization and decentralized generation, within complex regulatory environments.

Customers depend on energy and are looking for more choice, better control, and greater reliability. The costs of decentralized generation and storage have become more competitive and advancing technologies are transforming how utilities operate and interact with customers. Concurrently, climate change and the increased frequency of extreme weather events are shaping government energy policy. This is also creating a need to replace aging infrastructure and make investments to protect and harden energy systems to deliver energy reliability and system resiliency. These factors combined with inflation, higher interest rates and higher cost of capital place increased pressure on energy costs, and thus customer rates, at a time when affordability is a challenge.

Emera' s strategy is to invest in the energy future, including infrastructure renewal, centered on delivering value for customers, and in doing so creating value for shareholders. This includes:

- investing in cleaner and renewable sources of energy, in the related transmission assets, and in energy storage needed to support intermittent renewables;
- supporting increasing demand from customers and the ongoing electrification of other sectors;
- improving system reliability and resiliency, including replacing aging infrastructure and expanding systems to service new customers; and
- investing in new internal and customer-facing technologies for improved cost efficiency and better customer experiences.

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

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

- A 55 per cent reduction in carbon dioxide emissions by 2025.
- The retirement of Emera' s last existing coal unit no later than 2040.
- An 80 per cent reduction in carbon dioxide emissions by 2040.

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

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

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

DESCRIPTION OF THE BUSINESS

Business Segments

Emera' s reportable segments are:

- **Florida Electric Utility**, which consists of TEC;
- **Canadian Electric Utilities**, which includes NSPI and ENL, a holding company with equity interests in NSPML (100 per cent) and the LIL (31 per cent);
- **Gas Utilities and Infrastructure**, which includes PGS, NMGC, Emera Brunswick Pipeline Company, SeaCoast and an equity interest in M&NP (12.9 per cent);
- **Other Electric Utilities**, which includes ECI, a holding company with regulated electric utilities which include BLPC, GBPC and an equity interest in Lucelec (19.5 per cent); and
- **Other**, which includes Emera Energy, Block Energy and corporate holding, financing companies and certain other investments.

General

Emera and its subsidiaries had 7,366 employees as at December 31, 2023, approximately 30 per cent of whom are unionized.

Operations by Segment

The following sections describe the operations included in each of the Company' s reportable segments.

Florida Electric Utility

Florida Electric Utility consists of TEC, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. TEC has $12 billion USD of assets, approximately 840,000 customers and 2,546 employees as at December 31, 2023.

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

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

For further details on TEC' s regulatory environment, base rates and recovery mechanisms, refer to Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which are hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

Market and Sales

TEC Revenue and Sales Volumes by Customer Class				
	Electric Revenues (%)		GWh Electric Sales Volumes (%)	
For the year ended December 31	**2023**	**2022**	**2023**	**2022**
Residential	64.9	54.7	49.0	48.4
Commercial	30.4	26.4	30.7	30.2
Industrial	7.7	7.0	9.9	10.1
Other	(3.0)[1]	11.9	10.4	11.3
Total	**100.0**	**100.0**	**100.0**	**100.0**

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

Energy Sources and Generation

As at December 31, 2023, TEC owns 6,433 MW of generating capacity, of which 74 per cent is natural gas fired, 19 per cent is solar and 7 per cent is coal. TEC owns 2,192 kilometres of transmission facilities and 20,299 kilometres of distribution facilities. TEC meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

System Operations

TEC' s Energy Control Center co-ordinates and controls the electric generation, transmission and distribution facilities. The Energy Control Center is linked to the generating stations and other key facilities through the Supervisory Control and Data Acquisition system, a communication network used by system operators for remote monitoring and control of the power system assets.

Through interconnection agreements with our neighboring electric utilities within the Florida Region, TEC' s system has access to other regional power systems and the rest of the interconnected North American electric bulk power system. The interconnection of power systems enhances the cost effectiveness, reserve capacity and reliability of participating power systems. As a member of the Florida Reserve Sharing Group, TEC has immediate access to reserve generating capacity from all other group members.

Contribution to Consolidated Net Income

Florida Electric Utility' s contribution to consolidated net income was $466 million USD in 2023 (2022 – $458 million USD).

Seasonal Nature

Electric sales volumes are primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal. In Florida, Q3 is the strongest period for electricity sales, reflecting warmer weather and cooling demand.

Capital Investments

In 2023, capital investments, including AFUDC, in the Florida Electric Utility segment were $1.3 billion USD (2022 – $1.1 billion USD). In 2024, capital investment is expected to be approximately $1.3 billion USD, including AFUDC. Capital projects include solar investments, grid modernization, storm hardening investments and other infrastructure investments.

Environmental Considerations

TEC has significant environmental considerations. TEC operates stationary sources with air emissions regulated by the Clean Air Act. Its operations are also impacted by provisions in the Clean Water Act and federal and state legislative initiatives on environmental matters.

Hazardous Air Pollutants

All of TEC' s conventional coal-fired units are already equipped with electrostatic precipitators, scrubbers and selective catalytic reduction systems, and the Polk Unit 1 integrated gasification combined-cycle unit emissions are minimized in the gasification process. Therefore, TEC has minimized the impact of the EPA' s current Mercury Air Toxics Standards ("MATS") and has demonstrated compliance on all applicable units with the most stringent "Low Emitting Electric Generating Unit" classification for the EPA' s current MATS with nominal additional capital investment.

Carbon Reductions and GHG

In June 2019, the EPA released a final rule, named the Affordable Clean Energy ("ACE") rule, to establish emission guidelines for states to address GHG emissions from existing coal-fired electric generating units ("EGUs"). EPA released a proposed rule establishing CO_2 emission standards for new and existing fossil fuel-fired power plants. As proposed under Section 111 of the Clean Air Act, the New Source Performance Standards and Best System of Emission Reduction guidelines would require affected electric generating units to achieve CO_2 emission limits thorough the implementation of carbon capture and sequestration, or low-GHG hydrogen co-firing. The proposed rule also repeals the ACE rule promulgated under the Trump Administration. TEC expects one or more units to be subject to the rule, if finalized in its current form.

TEC expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, TEC could seek to recover those costs through a base-rate proceeding.

Ozone

On December 31, 2020, the EPA published a final rule to retain the national ambient air quality standards ("NAAQS") for photochemical oxidants including ozone, originally adopted in 2012. Under the Clean Air Act, the EPA is required to review the NAAQS every five years and, if appropriate, revise it. The EPA has announced that the NAAQS is currently under review, which could result in revisions to the standard affecting compliance in TEC' s service territory. The impact of this potential new standard on the operations of TEC will depend on the standard that is ultimately adopted and on the outcome of any related litigation or other developments.

Water Supply and Quality

The EPA' s final rule under 316(b) of the Clean Water Act (effective October 2014) addresses perceived impacts to aquatic life by cooling water intakes and is applicable to TEC' s Bayside and Big Bend Power Stations. Polk Power Station is not covered by this rule since it does not operate an intake on waters of the U.S. TEC has two ongoing projects (one for Bayside and one for Big Bend) that require compliance with the rule. The Florida Department of Environmental Protection ("FDEP") agreed with TEC' s proposed plan for Bayside and TEC began a multi-year construction project to install new fish-friendly modified traveling screens and a fish return in 2022. Compliance study elements have been completed and submitted for Bayside. TEC is negotiating an alternative schedule for a portion of the compliance requirements with the Big Bend modernization project, with the remainder of the compliance requirements to be determined and completed at a later date. The full impact of the regulations on TEC will depend on the outcome of subsequent legal proceedings challenging the rule, the results of the study elements performed as part of the rules' implementation, and the actual requirements established by FDEP.

The final EPA rule for existing steam electric effluent limit guidelines (“ELGs”) became effective January 4, 2016 and establishes limits for certain wastewater discharges. The ELGs are expected to be incorporated into National Pollutant Discharge Elimination System (“NPDES”) permit renewals for Big Bend Station and Polk Power Station to achieve compliance as soon as possible after November 1, 2018, but no later than December 31, 2023. The EPA proposed a new rule in March 2023 to strengthen discharge limits that is expected to be finalized in 2024.

The preliminary draft of the NPDES Permit for Big Bend stated that effluent limitations for total recoverable arsenic, mercury, and selenium and total nitrate/nitrite for flue gas desulfurization wastewater are applicable no later than December 31, 2023. Big Bend completed construction of a deep injection well system in December 2023 for disposal of various wastewaters. The effluent limitations do not apply to Polk Power Station.

Superfund and Former Manufactured Gas Plant Sites

Previously, TEC had been a potentially responsible party (“PRP”) for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, PGS is also now a PRP for those sites (in addition to third party PRPs for certain sites). For further details, refer to Note 27, Commitments and Contingencies – Legal Proceedings - Superfund and Former Manufactured Gas Plant Sites, in the Audited Financial Statements, which is hereby incorporated by reference, a copy of which is available electronically under Emera’ s profile on SEDAR+ at www.sedarplus.ca.

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 a 100 per cent equity investment in NSPML and a 31 per cent equity investment in LIL: two transmission investments related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls hydroelectric project (“Muskrat Falls”) on the Lower Churchill River in Labrador.

NSPI

NSPI is the primary electricity supplier in Nova Scotia, providing electricity generation, transmission and distribution services to approximately 549,000 customers with $7.2 billion in assets and 2,179 employees as at December 31, 2023.

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

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through regularly scheduled 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 and recovered from or returned to customers in subsequent periods.

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.

For further details on NSPI’ s regulatory environment and recovery mechanisms, refer to Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which are hereby incorporated by reference, a copy of which is available electronically under Emera’ s profile on SEDAR+ at www.sedarplus.ca.

Market and Sales

NSPI Revenue and Electricity Sales Volumes by Customer Class				
	Electric Revenues (%)		GWh Electric Sales Volumes (%)	
For the year ended December 31	**2023**	**2022**	**2023**	**2022**
Residential	55.7	50.8	47.8	46.1
Commercial	28.4	26.0	29.2	28.8
Industrial	13.4	21.5	20.7	23.7
Other	2.5	1.7	2.3	1.4
Total	**100.0**	**100.0**	**100.0**	**100.0**

Energy Sources and Generation

NSPI owns 2,422 MW of generating capacity, of which 44 per cent is coal and/or oil-fired, 28 per cent is natural gas and/or oil, 19 per cent is hydro, wind, or solar, 7 per cent is petroleum coke and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from IPPs, and COMFIT participants, which own 532 MW of capacity. NSPI also has rights to 153 MW of Maritime Link capacity, representing Nalcor' s NS Block delivery obligations, as discussed below.

Nalcor is obligated to provide NSPI with approximately 900 GWh of energy annually over 35 years. In addition, for the first five years of the NS Block, Nalcor is obligated to provide approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. The Energy Access Agreement enables NSPI to access a market-priced bid from Nalcor for up to 1.8 Terawatt hours ("TWh") of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

System Operations

NSPI' s Control Center Operations co-ordinates and controls the electric generation, transmission and distribution facilities with the goal of providing safe, reliable and efficient electricity supply while adhering to applicable environmental requirements and regulations. The Control Center is linked to the generating stations and other key facilities through the Supervisory Control and Data Acquisition system, a software applicaction used by system operators for remote monitoring and control of the power system assets via the company' s telecommunication networks.

Through interconnection agreements with NB Power and with Newfoundland and Labrador Hydro, NSPI' s system has access to other regional power systems and the interconnected North American bulk electric system. The interconnection of power systems enhances the cost effectiveness, reserve capacity and reliability of participating power systems. The interconnection agreements also provide participating utilities with a source of reserve power, subject to availability, transmission line capacity and the requirements of the supplier.

NSPI is a member of the NPCC, a body whose primary role is promoting the reliability of the interconnected power systems throughout the Northeastern United States and Eastern Canada (Nova Scotia, New Brunswick, Quebec, Ontario) under the regulatory authority of NERC. NERC and NPCC reliability standards and criteria are approved for enforcement in Nova Scotia by the UARB. NSPI complies with NPCC criteria and NERC standards for the design, planning and operation of NSPI' s portion of the interconnected bulk electric system.

Transmission and Distribution

NSPI transmits and distributes electricity from its generating stations to its customers. NSPI' s transmission system consists of approximately 5,000 km of transmission facilities. The distribution system consists of approximately 28,000 km of distribution facilities, which includes distribution supply substations.

ENL

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' 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.

LIL

ENL is a limited partner with Nalcor in LIL. Construction of the LIL is complete and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada' s Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

Upon issuance of the Commissioning Certificate, AFUDC equity earnings ceased and cash equity earnings and return of equity to Emera commenced. The first distribution was received from the LIL partnership in Q4 2023.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera' s current equity investment is $747 million, comprised of $410 million in equity contribution and $337 million of accumulated equity earnings. Emera' s total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million once the final costing has been confirmed by Nalcor to determine the amount of the remaining investment.

Contribution to Consolidated Net Income and Adjusted Net Income

Canadian Electric Utilities' contribution to consolidated net income was $247 million in 2023 (2022 - $215 million). Canadian Electric Utilities' contribution to Emera' s consolidated adjusted net income was $247 million in 2023 (2022 - $222 million). For a reconciliation of Canadian Electric Utilities' adjusted net income to consolidated net income, refer to the "Non-GAAP Financial Measures and Ratios" and "Financial Highlights – Canadian Electric Utilities" sections of Emera' s MD&A, which is incorporated herein by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

Seasonal Nature

Electric sales volumes are primarily driven by weather, number of customers, general economic conditions, and demand side management activities. Residential and commercial electricity sales are seasonal in Nova Scotia, with Q1 historically generating the highest sales, reflecting colder weather and fewer daylight hours in the winter season.

Capital Investment

NSPI

NSPI' s capital investments in 2023 were $451 million (2022 – $540 million), including AFUDC. In 2024, NSPI expects to invest $435 million, including AFUDC, primarily in capital projects to support power system reliability and reliable service for customers.

NSPML

NSPML does not anticipate any significant capital investment in 2024.

Environmental Considerations

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. NSPI faces risks associated with achieving climate-related and environmental legislative requirements, including the risk of non-compliance, which could adversely affect NSPI' s operations and financial performance. For further discussion on these risks and environmental legislation and regulations, refer to the "Enterprise Risk and Risk Management" section of the MD&A, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

Other Environmental Legislation and Regulations

There have been several recent environmental developments at both the federal and provincial levels, as described below in the "General Development of the Business – Canadian Electric Utilities - NSPI" section. For additional information on environmental regulations affecting NSPI, see also NSPI' s 2023 Annual Information Form, a copy of which is available electronically under NSPI' s profile on SEDAR+ at www.sedarplus.ca.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure includes PGS, NMGC, SeaCoast, Brunswick Pipeline and Emera' s equity 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.

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 on which NMGC has transportation capacity and NMGC' s intrastate transmission and distribution system for delivery to customers.

Market and sales

PGS, NMGC and SeaCoast Revenue and Sales Volumes by Customer Class				
	Gas Revenues (%)		Therms Gas Sales Volumes (%)	
For the year ended December 31	**2023**	**2022**	**2023**	**2022**
Residential	50.3	49.2	13.2	14.4
Commercial	29.5	28.3	26.8	28.7
Industrial	6.5	5.1	51.5	49.1
Other	13.7	17.4	8.5	7.8
Total	**100.0**	**100.0**	**100.0**	**100.0**

PGS

As at December 31, 2023, PGS serves approximately 490,000 customers with $2.8 billion USD in assets and 767 employees. The PGS system includes approximately 24,300 kilometres of natural gas mains and 13,500 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2 billion therms in 2023.

PGS is regulated by the FPSC. Rates are set at a level that allow the utilities to collect total revenues or revenue requirements equal to their cost to provide service, plus an appropriate return on invested capital.

Beginning in 2024, the approved ROE range for PGS is 9.15 per cent to 11.15 per cent (2023 – 8.9 per cent to 11.0 per cent), based on an allowed equity capital structure of 54.7 per cent (2023 – 54.7 per cent). An ROE of 10.15 per cent (2023 – 9.9 per cent) is used for the calculation of return on investments recovered through cost recovery clauses.

For further details on PGS' regulatory environment and recovery mechanisms, refer to Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which are hereby incorporated by reference, a copy of which is available electronically under Emera's profile on SEDAR+ at www.sedarplus.ca.

NMGC

As at December 31, 2023, NMGC serves approximately 540,000 customers with $1.8 billion USD in assets and 725 employees. NMGC's system includes 2,408 km of transmission lines and 17,657 km of distribution lines. Annual natural gas throughput was 1 billion therms in 2023.

NMGC is subject to regulation by the NMPRC. Rates are set 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 is 9.375 per cent on an allowed equity capital structure of 52 per cent.

For further details on NMGC's regulatory environment and recovery mechanisms, refer to Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which are hereby incorporated by reference, a copy of which is available electronically under Emera's profile on SEDAR+ at www.sedarplus.ca.

EBPC

EBPC owns Brunswick Pipeline, a regulated 145-km pipeline delivering re-gasified liquefied natural gas from the Saint John LNG import terminal near Saint John, New Brunswick to markets in the Northeastern United States. The pipeline travels through southwest New Brunswick and connects with M&NP at the Canada/U.S. border near Baileyville, Maine.

Since its commissioning in July 2009, the pipeline has been used solely to transport natural gas for RENAC under a 25-year firm service agreement, which expires in 2034. Brunswick Pipeline is regulated by the CER, which has classified it as a Group II pipeline. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis, as opposed to a regulatory approval process. 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 with RENAC, as noted above. The firm service agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract.

Economic Dependence

Brunswick Pipeline has a 25-year firm service agreement with RENAC, which expires in 2034. The risk of non-payment is mitigated as Repsol, the parent company of RENAC, has provided EBPC with a guarantee for all RENAC's payment obligations under the firm service agreement.

M&NP

Emera owns a 12.9 per cent interest in M&NP, which is a 1,400 km pipeline that transports natural gas throughout markets in Atlantic Canada and the Northeastern United States.

Contribution to Consolidated Net Income

Gas Utilities and Infrastructure’ s contribution to consolidated net income was $158 million USD in 2023 (2022 – $170 million USD).

Seasonal Nature

Gas sales volumes are primarily driven by general economic conditions, population and weather. Residential and commercial gas sales are seasonal. In Florida and New Mexico, Q1 is the strongest period for gas sales due to colder weather and heating demand.

Capital Investment

Capital investments, including AFUDC, in the Gas Utilities and Infrastructure segment in 2023 were $495 million USD (2022 - $436 million USD). In 2024, capital investment is expected to be approximately $465 million USD, including AFUDC. PGS and NMGC will make investments to maintain the reliability of their systems and support customer growth.

Environmental Considerations

PGS’ s operations are subject to federal, state and local statutes, rules and regulations relating to the discharge of materials into the environment and the protection of the environment that generally require monitoring, permitting and ongoing expenditures. Previously, TEC had been a potentially responsible party (“PRP”) for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, Peoples Gas System, Inc. is also now a PRP for those sites (in addition to third party PRPs for certain sites). For further details, refer to Note 27, Commitments and Contingencies – Legal Proceedings - Superfund and Former Manufactured Gas Plant Sites, in the Audited Financial Statements, which is hereby incorporated by reference, a copy of which is available electronically under Emera’ s profile on SEDAR+ at www.sedarplus.ca.

Brunswick Pipeline is subject to both federal and provincial environmental regulations. Brunswick Pipeline has comprehensive integrity, safety and environmental programs in place, including an integrated management system to ensure compliance and continuous improvement of its integrity, safety and environmental programs. Brunswick Pipeline also conducts regularly scheduled physical inspections of the pipeline and its right-of-way.

Other Electric Utilities

Other Electric Utilities includes ECI, a holding company with regulated electric utilities. ECI’ s regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island and a 19.5 per cent equity investment in Lucelec on the island of St. Lucia.

Market and Sales

Other Electric Utilities operating revenues for 2023 were $390 million USD (2022 – $398 million USD) and electric sales volumes were 1,260 GWh (2022 – 1,239 GWh).

BLPC

As at December 31, 2023, BLPC serves approximately 134,000 customers with $517 million USD of assets and a workforce of 414 employees. BLPC owns 243 MW of generating capacity, of which 96 per cent is oil-fired and 4 per cent is solar. BLPC' s transmission system consists of 188 km of transmission lines, including major substations connected to the transmission and distribution system. The distribution system consists of 3,839 km of distribution lines which includes distribution supply substations.

BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation.The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

BLPC is regulated by the FTC. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC' s approved regulated return on rate base is 10 per cent.

GBPC

As at December 31, 2023, GBPC serves approximately 19,000 customers, with $334 million USD of assets and a workforce of 205 employees. GBPC owns 98 MW of oil-fired generation, approximately 90 kilometres of transmission facilities and 994 kilometers of distribution facilities.

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 approved regulatory return on rate base is 8.52 per cent for 2024 (2023 – 8.32 per cent). For further details on GBPC' s regulatory environment and recovery mechanisms, refer to Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

System Operation

BLPC and GBPC have system control centres that co-ordinate and control their electric generation and transmission facilities with the goal of providing a reliable and secure electricity supply while maintaining economy of operations. The generation and transmission system control centres are linked to their generating stations and other key parts of their systems by the "Supervisory Control and Data Acquisition" systems, with fibre optic, voice and data communications networks.

Transmission and Distribution

BLPC and GBPC transmit and distribute electricity from their generating stations to their customers.

Contribution to Consolidated Net Income and Adjusted Net Income

Other Electric Utilities' contribution to consolidated net income was $28 million USD in 2023 (2022 – a loss of $35 million USD). Other Electric Utilities' contribution to consolidated adjusted net income was $26 million USD in 2023 (2022 – $23 million USD). For a reconciliation of Other Electric Utilities adjusted net income to consolidated net income, refer to the "Non-GAAP Financial Measures and Ratios" and "Financial Highlights – Other Electric Utilities" sections of Emera' s MD&A, which is incorporated herein by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

Seasonal Nature

Electricity sales and related generation varies significantly over the year in the Caribbean; Q3 is typically the strongest period, reflecting warmer weather. Grand Bahama is also particularly prone to tropical storm and hurricane impacts during Q3.

Capital Investment

Other Electric Utilities capital investments (including AFUDC) for 2023 were $47 million USD (2022 – $48 million USD). In 2024, capital investment is expected to be approximately $80 million USD, primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

Environmental Considerations

Emera’ s Caribbean utilities have implemented formal health & safety and environmental and management systems to assist in safeguarding the health and safety of its employees, contractors and customers while ensuring protection of the environment.

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 Block Energy. Emera Energy consists of EES, a wholly owned physical energy marketing and trading business and an equity investment in a 50 per cent joint venture ownership of Bear Swamp, a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts. Block Energy 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 U.S. It also includes costs associated with corporate activities that are not directly allocated to the operations of Emera’ s subsidiaries and investments.

Emera Energy

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

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.

Contribution to Consolidated Net Income and Adjusted Net Income

Other' s contribution to consolidated net income was a loss of $147 million in 2023 (2022 – loss of $39 million). Other' s contribution to consolidated adjusted net income was a loss of $314 million in 2023 (2022 – loss of $218 million). For further information on the non-GAAP measure adjusted net income, refer to the "Non-GAAP Financial Measures and Ratios" and "Financial Highlights – Other" sections of the MD&A, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

Capital Investment

In 2024, capital investment in the Other segment is not expected to be significant.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History and Changes Expected in 2024

The following discussion summarizes key developments in Emera' s business and operations over the last three completed financial years and changes that are expected to occur during the current financial year.

Florida Electric Utility

Base Rates

On August 6, 2021, TEC filed with the FPSC a joint motion for approval of a settlement agreement by TEC and the intervenors in relation to its rate case filed with the FPSC in April 2021. On October 21, 2021, the FPSC approved a settlement agreement filed by TEC. The settlement agreement allows for an increase of $191 million USD annually, effective January 2022. This increase consisted 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 August 16, 2022, the FPSC approved TEC' s request to increase revenue and ROE due to increases in the 30-year United States Treasury bond yield rate. Effective July 1, 2022, the new mid-point ROE is 10.20 per cent, and the range is 9.25 per cent to 11.25 per cent.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC' s ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 million USD for 2026 and 2027, respectively. TEC' s proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024 with a decision expected by the end of 2024.

Fuel Recovery

The mid-course fuel adjustment requested by TEC on July 19, 2021, was approved on August 3, 2021. The rate increase, effective with September 2021 customer bills, covered higher fuel and capacity costs of $83 million USD, and was spread over customer bills from September through December 2021.

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

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

Solar Projects

During 2017 to 2021, TEC invested $850 million USD in 600 MW of utility-scale solar photovoltaic projects, which is recoverable through FPSC-approved SoBRAs. AFUDC was 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.

On October 12, 2021, the FPSC approved the true-up filing for SoBRA tranche 3, included in base rates as of January 2020. A $4 million USD true-up was returned to customers during 2021. No true-up for SoBRA tranche 4 was required.

Big Bend Modernization Project

TEC invested $876 million USD, including $91 million USD of AFUDC, during 2018 through 2022 to modernize the Big Bend Power Station. The modernization project repowered Big Bend Unit 1 with natural gas combined-cycle technology and eliminated coal as this unit’ s fuel. As part of the modernization project, TEC retired the Unit 1 components that will not be used in the modernized plant in 2020 and Big Bend Unit 2 in 2021. TEC retired Big Bend Unit 3 in 2023 as it is in the best interest of the customers from an economic, environmental risk and operational perspective. On December 31, 2021, the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, of $636 million USD and $267 million USD in accumulated depreciation were reclassified to a regulatory asset on the balance sheet.

TEC’ s 2021 settlement agreement provides recovery for the Big Bend Modernization project in two phases. The first phase was a revenue increase to cover the costs of the assets in service during 2022, among other items. The remainder of the project costs were recovered as part of the 2023 subsequent year adjustment. The settlement agreement also includes a new charge to recover the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, which are spread over 15 years, effective January 1, 2022. This recovery mechanism is authorized by and survives the term of the settlement agreement approved by the FPSC in 2021.

Storm Reserve

In September 2022, TEC was impacted by Hurricane Ian with $119 million USD of restoration costs charged against TEC’ s FPSC approved storm reserve. Total restoration costs charged to the storm reserve exceeded the reserve balance and have been deferred as a regulatory asset for future recovery.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the

FPSC approved TEC' s petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings. TEC will determine the timing of the request for recovery of Hurricane Idalia costs at a future time.

Storm Protection Cost Recovery Clause and Settlement Agreement

The Storm Protection Plan ("SPP") Cost Recovery Clause provides a process for Florida investor-owned utilities, including TEC, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. 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. A settlement agreement was approved on August 10, 2020, and TEC' s cost recovery began in January 2021. The previously approved plan addressed the years 2020 through 2022, and in April 2022 TEC submitted a new plan to determine cost recovery in 2023, 2024 and 2025. On October 4, 2022, the FPSC approved TEC' s current SPP for those years.

For more information, refer to the "Regulatory Environments and Updates – Florida Electric Utility" section of Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca

Canadian Electric Utilities

NSPI

General Rate Application

On February 2, 2023, the UARB approved the General Rate Application Settlement Agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and further average increase of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB' s established FAM process. It also established a storm rider and a demand-side management rider. On March 27, 2023 the UARB issued a final order approving the electricity rates effective on February 2, 2023.

Fuel Recovery

For the period of 2020 through 2022, NSPI operated under a three-year fuel stability plan with no fuel rate adjustments related to the under-recovery of fuel and fuel-related costs in the period.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding FAM balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024. A decision is expected in the first half of 2024. It is anticipated that NSPI will apply to the UARB later in 2024 to collect additional under-recovered fuel amounts in 2025 or future periods, subject to the approval of the UARB.

Extra Large Industrial Active Demand Tariff

On July 5, 2023, NSPI received approval from the UARB to change the methodology in which fuel cost recovery from an industrial customer is calculated. Due to significant volatility in commodity prices in 2022, the previous methodology did not result in a reasonable determination of the fuel cost to serve this customer. The change in methodology, effective January 1, 2022, results in a shifting of fuel costs from this industrial customer to the FAM. This adjustment was recorded in Q2 2023 resulting in a $51 million increase to the FAM regulatory asset and an offsetting decrease to unbilled revenue within Receivables and other current assets. This adjustment had minimal impact on earnings.

Hurricane Fiona

On September 24, 2022, Nova Scotia was struck by Hurricane Fiona, which made landfall as a post-tropical storm equivalent to a Category 2 hurricane. The storm had sustained winds of over 100 km per hour and peak gusts of approximately 180 km per hour. This historic storm for Nova Scotia caused significant and widespread damage to NSPI' s transmission and distribution system and at the height of the storm approximately 415,000 customers lost power. The total cost of the restoration was approximately $120 million, of which $96 million was capitalized to "PP&E" and $24 million deferred to "Other long-term assets" for future amortization, subject to UARB approval.

On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023 the $24 million is deferred to "Other long-term assets", pending UARB approval.

Post-Tropical Storm Lee

On September 16, 2023, Nova Scotia was struck by post-tropical storm Lee and as a result, approximately 280,000 customers lost power. The total cost of storm restoration was $19 million, with $9 million charged to OM&G, $5 million capitalized to PP&E and $5 million deferred to the UARB approved storm rider. The storm rider for each of 2023, 2024, and 2025 allows NSPI to apply to the UARB for deferral and recovery of expenses if major storm restoration expenses exceed approximately $10 million in any given year. The application for deferral of the storm rider is made in the year following the year of the incurred costs, with recovery beginning in the year after the application.

Regulatory Matters – General

For more information, refer to the "Regulatory Environments and Updates – Canadian Electric Utilities – NSPI" section of Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

Environmental Legislation and Regulations

Greenhouse Gas Emissions

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.

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

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 November 5, 2021, the Nova Scotia 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.

In March 2022 the federal government issued their 2030 Emission Reduction Plan required under the Canadian Net-Zero Emissions Accountability Act. The Emission Reduction Plan acknowledges the federal and provincial emission reduction goals and programs currently legislated and also signals the intention for implementation of further emission reduction goals, including the federal intention of attaining a net-zero electricity grid by 2035. Subsequent regulations will be required to detail how this goal will be achieved.

Clean Electricity Solutions Task Force

The Clean Electricity Solutions Task Force (the "Task Force") was created by the Province in April 2023 to advise the provincial government on Nova Scotia' s transition away from coal to more renewable sources of energy. On February 23, 2024, the Task Force released its report and recommendations, based on engagement with stakeholders, including NSPI. The Task Force report focuses on findings related to system operations, regulatory oversight, reliability, transmission and affordability. The Task Force announced a number of recommendations including a strengthening of the authority and independence of the regulator and the establishment of an independent system operator in order to support the continuing transition to clean energy and the achievement of federal and provincial clean energy goals and legislation. The Province announced they intend to accept these recommendations and will table enabling legislation in its upcoming session which starts February 27, 2024.

Nova Scotia Renewable Electricity Regulations

Under the provincially legislated RER , starting in 2020, 40 per cent of electric sales must be generated from renewable sources. NSPI met this target in 2023, with 43 per cent of NSPI' s electric sales coming form renewable sources, subject to a compliance filing.

Due to the delay of NSPI receiving energy form the NS Block, the Province provided NSPI with an alternative compliance plan that required NSPI to achieve 40 per cent of electric sales generated from renewable sources over the 2020 through 2022 period. With delivery of the NS Block commencing later than anticipated, as well as further interruptions in supply due to delays in the LIL, NSPI did not achieve the requirements of the alternative compliance plan.

On April 6, 2023, the Province levied a $10 million penalty on NSPI for non-compliance with the RER compliance period ending in 2022. The penalty was recorded in OM&G on the Consolidated Statements of Income. On May 26, 2023, NSPI initiated an appeal of the penalty through a proceeding with the UARB, as permitted under the RER. On October 12, 2023, the UARB decided that it will hear the appeal by giving due deference to the Province' s decision but permitting the filing of new evidence to support the parties' positions. The hearing for the matter is scheduled for June 2024 and a decision is expected before the end of 2024.

Carbon Pricing Regulations

In November 2022, the Province enacted amendments to the Environment Act which provided the framework for Nova Scotia to implement an OBPS to comply with the Government of Canada' s 2023 through 2030 carbon pollution pricing regulations effective January 1, 2023. The Government of Canada approved the Province' s proposed system, however the OBPS will be subject to an interim review by the Government of Canada of the standards effective for 2026. The final Output-Based Pricing System

Reporting and Compliance Regulations were prescribed by Order in Council dated January 30, 2024. The OBPS GHG emissions performance standards for large industrial GHG emitters that vary by fuel type. GHG emissions in excess of the prescribed intensity standards will be subject to a carbon price that starts at $65 per tonne in 2023 and will increase by $15 per tonne annually, reaching $170 per tonne by 2030. NSPI' s regulatory framework provides for the recovery of costs prudently incurred to comply with carbon pricing programs pursuant to NSPI' s FAM.

Nova Scotia Cap-and-Trade Program Regulations

NSPI was a participant in the Nova Scotia Cap-and-Trade Program and was subject to the 2019 through 2022 compliance period. On March 16, 2023, the Province provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 compliance period. As such, compliance costs accrued of $166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of $6 million were not refunded and no further costs were incurred to achieve compliance with the Nova Scotia Cap-and-Trade Program.

Other Legislation

Electricity Act Amendment

On November 9, 2023, the Province enacted amendments in the Electricity Act which permit the Governor in Council to approve energy storage projects proposed by a public utility and owned wholly or in majority by the public utility if the project is in the best interest of ratepayers. Further, the amendments to the Electricity Act expand the ability of the Province to require NSPI to enter into power purchase agreements with renewable generation facilities by further empowering the Province to require NSPI to enter into an agreement for the sale of the electricity to specified customers. This allows specified customers to buy renewable electricity from specified producers, with NSPI managing the transmission and sale of the energy. On December 21, 2023, the Governor in Council enacted regulations which directed NSPI to install three 50 MW four-hour duration grid-scale batteries as part of the regulated assets of NSPI.

Performance Standards Penalty Amendment

On April 12, 2023, the Province enacted amendments to the Public Utilities Act which increased the cumulative total of administrative penalties that could be levied by the UARB against NSPI for non-compliance with current and future performance standards in a calendar year from $1 million to $25 million. Any administrative penalties levied against NSPI must be credited to customers and NSPI cannot recover administrative penalties imposed through rates.

ENL

Maritime Link Project

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.

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

In December 2022, NSPML received UARB approval to collect up to $164 million from NSPI for the recovery of costs associated with the Maritime Link in 2023, subject to a monthly holdback of up to $2 million, which will increase to $4 million beginning December 2023, as discussed below.

On October 4, 2023 and January 31, 2024, the UARB issued decisions providing clarification on remaining aspects of the Maritime Link holdback mechanism primarily relating to release of past and future holdback amounts and requirements to end the holdback mechanism. In these decisions, the UARB agreed with the Company' s submission that $12 million ($8 million related to 2022 and $4 million relating to 2023) of the previously recorded holdback remain credited to NSPI' s FAM, with the remainder released to NSPML and recorded in Emera' s "Income from equity investments". NSPML did not record any additional holdback in Q4 2023. The UARB also confirmed that the holdback mechanism will cease once 90 per cent of NS Block deliveries are achieved for 12 consecutive months (subject to potential relief for planned outages or exceptional circumstances) and the net outstanding balance of previously underdelivered NS Block energy is less than 10 per cent of the contracted annual amount. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023. NSPML expects to file an application to terminate the holdback in 2024.

On December 21, 2023, NSPML received approval to collect up to $164 million from NSPI for the recovery of costs associated with the Maritime Link in 2024; subject to a holdback of up to $4 million a month, as discussed above.

Gas Utilities and Infrastructure

PGS

Base Rates

On November 19, 2020, the FPSC approved a settlement agreement filed by PGS. The settlement agreement allowed 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 provided PGS the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

NMGC

Base Rates

On December 13, 2021, NMGC filed a rate case with the NMPRC for new rates to become effective January 2023. On May 20, 2022, NMGC filed an unopposed settlement agreement with the NMPRC for an increase of $19 million USD in annual base revenues. The rates reflect the recovery of increased operating costs and capital investments in pipelines and related infrastructure. The NMPRC approved the settlement agreement on November 30, 2022.

On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective Q4 2024. NMGC requested $49 million USD in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent. A final order from the NMPRC is expected in Q3 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 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 from July 1, 2021, to December 31, 2023.

For more information, refer to the "Regulatory Environments and Updates – Gas Utilities and Infrastructure" section of Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which is hereby incorporated by reference, a copy of which is available electronically under Emera's profile on SEDAR+ at www.sedarplus.ca.

Other Electric Utilities

BLPC

General Rate Review

In 2021 BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the "Motion") and applied for a stay of the FTC's decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

On December 1, 2023, BLPC appealed certain aspects of the FTC's February 15 and November 20, 2023, decisions to the Supreme Court of Barbados in the High Court of Justice (the "Court") and requested that they be stayed. On December 11, 2023, the Court granted the stay. BLPC's position is that the FTC made errors of law and jurisdiction in their decisions and believes the success of the appeal is probable, and as a result, the adjustments to BLPC's final rates and rate base, including any adjustments to regulatory assets and liabilities, have not been recorded at this time. Management does not expect the final decision and order to have a material impact on adjusted net income.

Clean Energy Transition Program ("CETP")

On May 31, 2023, the FTC approved BLPC's application to establish an alternative cost recovery mechanism to recover prudently incurred costs associated with its CETP (the "Decision"). The mechanism is intended to facilitate the timely recovery between rate cases of costs associated with approved renewable energy assets. BLPC will be required to submit an individual application for the recovery of costs of each asset through the cost recovery mechanism, meeting the minimum criteria as set out in the Decision. On October 5, 2023, BLPC applied to the FTC to recover the costs of a battery storage system through the CETP.

GBPC

Base Rates

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 became effective April 1, 2022, allows for an increase in revenues of $3.5 million USD. The rates include a regulatory ROE of 12.84 per cent.

Fuel Recovery

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

Storm Restoration Costs – Hurricane Matthew

As part of the recovery of costs incurred as a result of Hurricane Matthew in 2016, 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. As part of its decision on GBPC' s application for rate review, 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.

For more information, refer to the "Regulatory Environments and Updates – Other Electric Utilities" section of Note 6, Regulatory Assets and Liabilities, in the Audited Financial Statements, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

USGAAP – Exemptive Relief

On January 28, 2021, the International Accounting Standards Board ("IASB") published an Exposure Draft: *Regulatory Assets and Regulatory Liabilities*, which proposes the accounting model under which a company subject to rate regulation that meets the scope criteria would recognize regulatory assets and liabilities. The proposed effective date is annual reporting periods beginning on or after a date 18-24 months from the date of publication of the standard. Emera was granted exemptive relief by Canadian securities regulators on September 13, 2022, and under the Companies Act (Nova Scotia) on October 12, 2022, each allowing Emera to continue to report its financial results in accordance with USGAAP (collectively the "Exemptive Relief"). The Exemptive Relief will terminate on the earliest of: (i) January 1, 2027; (ii) if the Company ceases to have rate-regulated activities, the first day of the Company' s financial year that commences after the Company ceases to have rate-regulated activities; and (iii) the first day of the Company' s financial year that commences on or following the later of: (a) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities ("Mandatory Rate-regulated Standard"); and (b) two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard. The Exemptive Relief replaces similar relief that had been granted to Emera in 2018 and would have expired by no later than January 1, 2024.

The Company will continue to monitor the development of the Mandatory Rate-regulated Standard and assess the impact on the existing Exemptive Relief.

Financing Activity

At-The-Market 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.

During 2021, approximately 4.99 million common shares were issued under the 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.

During 2022, approximately 4.07 million common shares were issued under the ATM Program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs). As at December 31, 2022, an aggregate gross sales limit of $207 million remained available for issuance under the ATM Program, which expired on September 5, 2023.

On November 14, 2023, 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 dated November 14, 2023 to the Company' s short form base shelf prospectus dated October 3, 2023. The ATM program is expected to remain in effect until November 4, 2025.

During 2023, approximately 8.29 million common shares were issued under the ATM Program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs) and an aggregate gross sales limit of $200 million remained available for issuance under the ATM Program.

During 2024, up to and including February 26, 2024, no common shares were issued under the ATM Program and an aggregate gross sales limit of $200 million remains available for issuance under the ATM Program.

Preferred Share Issuances

On April 6, 2021, Emera issued 8 million Series J First Preferred Shares 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.

On September 24, 2021, Emera issued 9 million Series L First Preferred Shares, 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 July 6, 2023, Emera announced it would not redeem the 10 million outstanding Series C First Preferred Shares. The holders of the Series C First Preferred Shares had the right, at their option, to convert all or any of their Series C First Preferred Shares, on a one-for-one basis, into Series D First Preferred Shares on August 15, 2023 or to continue to hold their Series C First Preferred Shares. On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C First Preferred Shares would be converted into Series D First Preferred Shares.

On July 6, 2023, Emera announced it would not redeem the 12 million outstanding Series H First Preferred Shares. The holders of the Series H First Preferred Shares had the right, at their option, to convert all or any of their Series H First Preferred Shares, on a one-for-one basis, into Series I First Preferred Shares on August 15, 2023 or to continue to hold their Series H First Preferred Shares. On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series H First Preferred Shares would be converted into Series I First Preferred Shares.

Senior Notes

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.

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030. The proceeds were used to repay Emera' s $500 million unsecured fixed rate notes, which matured in June 2023.

For more information on financing activities for Emera and its subsidiaries, please refer to the "Liquidity and Capital Resources" section of Emera' s MD&A, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

RISK FACTORS

For Emera' s risk factors, refer to the "Enterprise Risk and Risk Management" section of the MD&A and the "Principal Financial Risks and Uncertainties" section of Note 27, Commitments and Contingencies, to the Audited Financial Statements, which are each incorporated herein by reference, copies of which are available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

CAPITAL STRUCTURE

The authorized capital of Emera consists of an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. Each class of preferred shares is issuable in series.

As at December 31, 2023, 284,117,511 common shares, 4,866,814 Series A First Preferred Shares, 1,133,186 Series B First Preferred Shares, 10,000,000 Series C First Preferred Shares, 5,000,000 Series E First Preferred Shares, 8,000,000 Series F First Preferred Shares, 12,000,000 Series H First Preferred Shares, 8,000,000 Series J First Preferred Shares, 9,000,000 Series L First Preferred Shares, 2,200,525 Barbados DRs and 1,814,135 Bahamas DRs were issued and outstanding.

Common Shares

The holders of common shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Emera, other than separate meetings of holders of any other class or series of shares, and to one vote in respect of each common share held at such meetings.

The holders of common shares are entitled to dividends on a *pro rata* basis, as and when declared by the Board. Subject to the rights of the holders of the first preferred shares and second preferred shares, if any, who are entitled to receive dividends in priority to the holders of the common shares, the Board may declare dividends on the common shares to the exclusion of any other class of shares of Emera.

On the liquidation, dissolution or winding-up of Emera, holders of common shares are entitled to participate rateably in any distribution of assets of Emera, subject to the rights of holders of first preferred shares and second preferred shares, if any, who are entitled to receive the assets of the Company on such a distribution in priority to the holders of the common shares.

There are no pre-emptive, redemption, purchase or conversion rights attaching to the common shares. The foregoing description is subject to the “Share Ownership Restrictions” section below.

Emera First Preferred Shares

The first preferred shares of each series rank on 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 will be entitled, for only as long as the dividends remain in arrears, 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.

The first preferred shares of each series are not redeemable at the option of their holders. For a summary of the terms and conditions of the Company’ s authorized First Preferred Shares as of December 31, 2023, refer to Appendix “B” of this AIF.

Emera Second Preferred Shares

The second preferred shares have special rights, privileges, restrictions and conditions substantially similar to the first preferred shares, except that the second preferred shares rank junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of Emera in the event of liquidation, dissolution or winding-up of Emera. As at December 31, 2023, Emera had not issued any second preferred shares.

Share Ownership Restrictions

As required by the Reorganization Act and pursuant to the Privatization Act, the Articles of Emera provide that no person, together with associates thereof, may subscribe for, have transferred to that person, hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, or vote, in the aggregate, voting shares of Emera to which are attached more than 15 per cent of the votes attached to all outstanding voting shares of Emera.

The common shares, and in certain circumstances the Series A First Preferred Shares, Series B First Preferred Shares, Series C First Preferred Shares, Series E First Preferred Shares, Series F First Preferred Shares, Series H First Preferred Shares, Series J First Preferred Shares and Series L First Preferred Shares are considered to be voting shares for purposes of the constraints on share ownership.

Emera’ s Articles contain provisions for the enforcement of these constraints on share ownership including provisions for suspension of voting rights, forfeiture of dividends, prohibitions of share transfer and issuance, compulsory sale of shares and redemption, and suspension of other shareholder rights. The Board may require shareholders to furnish statutory declarations as to matters relevant to enforcement of the restrictions.

CREDIT RATINGS

Emera has the following credit ratings by the Rating Agencies:

	Moody’ s	S&P	Fitch
Corporate	Baa3	BBB	BBB
Outlook	Negative	Negative	Negative
Senior unsecured debt program	Baa3	BBB-	BBB
Hybrid Notes	Ba2	BB+	BB+
First Preferred Shares	N/A	P-3 (high)	BB+

Ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities and are indicators of the likelihood of the payment capacity and willingness of an issuer to meet its financial commitment in accordance with the terms of the obligation. The credit ratings assigned by the Rating Agencies are not recommendations to buy, sell, or hold securities in as much as such ratings are not a comment upon the market price of the securities or their stability for a particular investor. The credit ratings assigned to the securities may not reflect the potential impact of all risks on the value of the securities. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a Rating Agency in the future if in its judgment circumstances so warrant.

Moody’ s

Moody’ s credit ratings are on a long-term debt rating scale that ranges from Aaa to C, representing the range from highest to lowest quality of such rated securities. The rating of Baa3 obtained from Moody’ s in respect of the senior unsecured debt is the fourth highest of nine available rating categories and indicates that the obligations are subject to moderate credit risk. As such, they are considered medium-grade and may possess speculative characteristics. The rating of Ba2 from Moody’ s in respect of the Hybrid Notes is characterized as having speculative elements and being subject to substantial credit risk. It is the fifth highest of nine available rating categories. Moody’ s appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

S&P

S&P’ s credit ratings are on a long-term debt scale that ranges from AAA to D, representing the range from highest to lowest quality of such rated securities. The issuer rating of BBB obtained from S&P in respect of the corporate rating indicates that the issuer has adequate capacity to meet its financial commitments. The issue rating of BBB- from S&P in respect of the senior unsecured debt indicates that the obligations exhibit adequate protection parameters. The issue rating of BB+ from S&P in respect of the Hybrid Notes indicates that the obligations exhibit adequate projection parameters in the near term however the obligor may not have the capacity to meet its obligations in the long term. The issue and issuer ratings of BBB and BB are the fourth and fifth highest, respectively, of ten available ratings categories and the addition of either a “(+)” or a “(-)” designation after a rating indicates the relative standing within a particular category. In each case, however, adverse economic conditions or changing circumstances are more likely to lead to weakened capacity of the obligor to meet its financial commitments on the obligation.

A P-3 (high) rating with respect to Emera’ s issued and outstanding First Preferred Shares is the third highest of the eight standard categories of ratings utilized by S&P for preferred shares.

Fitch

Fitch’ s credit ratings are on a long-term debt scale that ranges from AAA to D, representing the range from highest to lowest quality of such rated securities. The rating of BBB obtained from Fitch in respect of the senior unsecured debt is the fourth highest of nine available rating categories and indicates that the issuer has adequate capacity to meet its financial commitments. The rating of BB from Fitch in respect of the

Hybrid Notes is characterized as having elevated default risk however business or financial flexibility exists that support servicing the financial commitments. The BB rating from Fitch is the fifth highest of nine available ratings categories and the addition of either a "(+)" or a "(-)" designation after a rating indicates the relative standing within a particular category. In each case, however, adverse economic conditions or changing circumstances are more likely to lead to weakened capacity of the obligor to meet its financial commitments on the obligation.

Emera has made, or will make, payments in the ordinary course to the Rating Agencies in connection with the assignment of ratings on both Emera and its securities. In addition, Emera has made customary payments in respect of certain subscription services provided to Emera by the Rating Agencies during the last two years.

For further information on the credit ratings of Emera and its subsidiaries, refer to the "Credit Ratings" section of the MD&A, which is hereby incorporated by reference, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca.

DIVIDENDS

Any dividend payments will be at the Board' s discretion based upon earnings and capital requirements and any other factors as the Board may consider relevant. On September 20, 2023 Emera extended its annual dividend growth rate target of four to five per cent through 2026. The Company targets a long-term dividend payout ratio of 70 to 75 per cent, and while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time.

Emera maintains the Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends and to participate in optional cash contributions for the purpose of purchasing 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 2023.

The Board approved the payment of the following dividends during the last three completed fiscal years, as summarized in the following table:

Class of Shares	2023	2022	2021
Common Shares(1), (2), (3)	$2.7875	$2.6775	$2.5750
Series A First Preferred Shares(4)	$0.5456	$0.5456	$0.5456
Series B First Preferred Shares	$1.5583	$0.6869	$0.4873
Series C First Preferred Shares(5)	$1.2873	$1.1802	$1.1802
Series E First Preferred Shares	$1.1250	$1.1250	$1.1250
Series F First Preferred Shares(6)	$1.0505	$1.0505	$1.0505
Series H First Preferred Shares(7)	$1.3140	$1.2250	$1.2250
Series J First Preferred Shares(8)	$1.0625	$1.0625	$0.6470
Series L First Preferred Shares(9)	$1.1500	$1.1500	$0.1638

(1) On September 24, 2021, Emera approved an increase in the annual common share dividend rate from $2.55 to $2.65. The first payment was effective November 15, 2021.

(2) On September 22, 2022, Emera approved an increase in the annual common share dividend rate from $2.65 to $2.76. The first payment was effective November 15, 2022.

(3) On September 20, 2023, Emera approved an increase in the annual common share dividend rate from $2.76 to $2.87. The first payment was effective November 15, 2023.

(4) The Series A First Preferred Shares annual dividend rate was reset from $0.6388 to $0.5456 for the five year period commencing August 15, 2020 and ending on (and inclusive of) August 14, 2025.

(5) The Series C First Preferred Shares annual dividend rate was reset from $1.18024 to $1.60852 for the five year period commencing August 15, 2023 and ending on (and inclusive of) August 14, 2028.

(6) The Series F First Preferred Shares annual dividend rate was reset from $1.0625 to $1.0505 for the five year period commencing February 15, 2020 and ending on (and inclusive of) February 14, 2025.

(7) The Series H First Preferred Shares annual dividend rate was reset from $1.2250 to $1.5810 for the five year period commencing August 15, 2023 and ending on (and inclusive of) August 14, 2028..

(8) The Series J First Preferred Shares with an annual dividend rate of $1.0625 (per share) were issued April 6, 2021.

(9) The Series L First Preferred Shares with an annual dividend rate of $1.150 (per share) were issued September 24, 2021.

Pursuant to the Income Tax Act (Canada) and corresponding provincial legislation, all dividends paid on Emera' s common shares and first preferred shares qualify as eligible dividends.

MARKET FOR SECURITIES

Trading Price and Volume

Emera' s common shares, Series A First Preferred Shares, Series B First Preferred Shares, Series C First Preferred Shares, Series E First Preferred Shares, Series F First Preferred Shares, Series H First Preferred Shares, Series J First Preferred Shares and Series L First Preferred Shares are listed and posted for trading on the TSX under the symbols "EMA", "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", respectively. The Barbados DRs are listed on the BSE under the symbol EMABDR. The Bahamas DRs are listed on the BISX under the symbol EMAB. The trading volume and high and low price for Emera' s securities for each month of 2023 are set out In Appendix "C" of this AIF.

At-The-Market Equity Program

On November 14, 2023, 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 dated November 14, 2023 to the Company' s short form base shelf prospectus dated October 3, 2023. The ATM program is expected to remain in effect until November 4, 2025, unless terminated prior to such date by the Company or otherwise in accordance with the terms of the equity distribution agreement. As at December 31, 2023, an aggregate gross sales limit of approximately $200 million remains available for issuance under the ATM program. For more information on the ATM Program, refer to "General Development of the Business – Financing Activity – At-The-Market Equity Program" above.

DIRECTORS AND OFFICERS

Directors

The following information is provided for each Director of Emera as at December 31, 2023(1):

Name, Residence, Principal Occupations During the Past Five Years	Director Since(2)	Committees(3)
M. Jacqueline Sheppard (Chair), Calgary, Alberta, Canada Chair of the Board since May 2014. Director of Suncor Energy Inc., a Canadian integrated energy company and of ARC Resources Ltd., a publicly traded Canadian energy company. Former Director of Alberta Investment Management Corporation (AIMCo), an institutional investment manager.(1) Former Executive Vice President, Corporate and Legal of Talisman Energy Inc. Founder and former Lead Director of Black Swan Energy Inc., an Alberta upstream energy company, which was sold in July 2021. Former Director of Cairn Energy PLC, a publicly traded UK-based international upstream company, as well as former director of the general partner of Pacific Northwest LNG LP and Chair of the Research and Development Corporation of the Province of Newfoundland and Labrador, a provincial Crown corporation, until June 2014.	2009	(4)
Scott C. Balfour, Halifax, Nova Scotia, Canada A Director and President and Chief Executive Officer of Emera since March 29, 2018. Mr. Balfour is a Director of many Emera subsidiaries, including being Chair of Tampa Electric Company and Nova Scotia Power Inc. He is a former director of Martinrea International Inc. He was Chief Operating Officer from 2016 to 2018 and was Executive Vice President and Chief Financial Officer of Emera from April 2012 to March 2016. From 1994 to 2011 he was Chief Financial Officer and then President of Aecon Group Inc., a Canadian publicly traded construction and infrastructure development company. He is also past Chair of the Ontario Energy Association.	2018	(5)
James V, Bertram Calgary, Alberta, Canada Chair of the Board, Keyera Corporation. Formerly President, and Chief Executive Officer of Keyera from its inception in 1998 until 2015, when he became Executive Chair. Previously Vice President – Marketing for the worldwide operations of Gulf Canada. Director of Methanex Corporation, the world' s largest producer and supplier of methanol to major international markets.	2018	Chair of HSEC and Member of MRCC
Henry E. Demone, Lunenburg, Nova Scotia, Canada Former Chair of High Liner Foods, the leading North American processor and marketer of value-added frozen seafood. Mr. Demone was President of High Liner Foods since 1989 and its President and Chief Executive Officer from 1992 to May 2015. He was interim Chief Executive Officer of High Liner Foods from August 2017 until April 2018. A Director of Saputo Inc.	2014	Chair of MRCC and Member of NCGC
Paula Y. Gold-Williams, San Antonio, Texas, U.S. Former President and CEO of CPS Energy, a fully integrated electric and natural gas municipal utility based in San Antonio, Texas. Currently serves as the Co-Chair of the Keystone Policy Center, having been a member of both the Policy Center and its Energy Board since 2016. Former .Board member and Treasurer of EPIcenter, an innovation think tank; incubator and accelerator; and strategic advisory organizationEnergy Pillar Co-Chair of Dentons' Global Smart Cities & Communities Initiatives and Think Tank. Advisory Board Serves on the US Secretary of Energy' s Advisory Board. A Director of ReNew Energy Global Plc, a renewable energy company based in India.	2022	Member of AC and HSEC
Kent M. Harvey, New York, New York, U.S. Former Chief Financial Officer for PG&E Corporation, an energy-based holding company, and the parent of Pacific Gas and Electric Company, one of the largest combined natural gas and electric energy companies in the United States.	2017	Chair of AC and Member of HSEC

B. Lynn Loewen, FCPA, FCA, Westmount, Quebec, Canada Former President of Minogue Medical Inc., a Canadian supplier of innovative medical technologies, supplies and equipment. Former President of Expertech Network Installation Inc., a Canadian network infrastructure service provider, from 2008 to 2011. Member of the Board of Directors of National Bank of Canada, a Canadian Chartered Bank, Chair of its Audit Committee and member of its Technology Comittee. Former member of the Board of Directors of Xplore Inc., a Canadian broadband service provider, and a member of its Audit Committee from 2021 to 2023. Former member of the Public Sector Pension Investment Board, serving on the Audit and Conflicts Committee and as Audit Committee Chair. Chancellor of Mount Allison University and a member of the Executive Committee and Chair of its Nominating and Governance Committee since 2018. Member of the Board of Regents from 1998 to 2008, serving as Chair from 2007-2008.	2013	Member of AC, HSEC and RSC
Ian E. Robertson, Oakville, Ontario, Canada A principal of the Northern Genesis Capital Group, an investment group focused on identifying and acquiring energy transition businesses which demonstrate strong sustainability and Environmental, Social and Governance (ESG) alignment. Former CEO of Algonquin Power & Utilities Corp. (Algonquin Power). Former member of the Board of Directors of Northern Genesis Acquisition Corp., Northern Genesis Acquisition Corp. II and Northern Genesis Acquisition Corp. III. Former Director of Embark Technology, Inc., an autonomous vehicle company,Largo Resources Ltd., Algonquin Power and Atlantica Sustainable Infrastructure plc.	2022	Member of AC and RSC
Andrea S. Rosen, Toronto, Ontario, Canada Former Vice-Chair of TD Bank Financial Group and President of TD Canada Trust. Director of Manulife Financial Corporation, a Canadian multinational insurance company and financial services provider; Ceridian HCM Holding Inc., a global human capital management software company and Element Fleet Management Corp., a global fleet management company, providing services and financing for commercial vehicle fleets. Former Director of Alberta Investment Management Corporation (“AIMCo.”). Former Director of Hiscox Ltd., a Bermuda-incorporated specialty insurer listed on the London Stock Exchange.	2007	Chair of NCGC and Member of AC
Karen H. Sheriff, Picton, Ontario, Canada Ms. Sheriff is past President and CEO of Q9 Networks Inc., and prior to that, President and CEO of Bell Aliant, Inc., from 2008 to 2014. She held senior leadership positions for more than nine years with BCE Inc. and currently serves on the BCE Inc. Board of Directors. She spent over 10 years at United Airlines in the areas of marketing, strategy, human resources, and finance. She is a former member of the Board of Directors of CPP Investments and WestJet Airlines Ltd.	2021	Member of MRCC, RSC and NCGC
Jochen E. Tilk, Toronto, Ontario, Canada Former Executive Chair of Nutrien Ltd., a Canadian global supplier of agricultural products and services based in Saskatoon, Saskatchewan. Former President and Chief Executive Officer of Potash Corporation of Saskatchewan. Previously President and Chief Executive Officer of Inmet Mining Corporation, a Canadian-based, international metals company. Mr. Tilk is a director of AngloGold Ashanti Limited, a publicly listed international gold mining company, headquartered in Johannesburg, South Africa. He is also Vice-Chair of the Princess Margaret Cancer Foundation, a not-for-profit organization. He is the former Chair of the board of directors of Canpotex Limited. Former Director of the Fertilizer Institute and the International Fertilizer Association.	2018	Chair of RSC and Member of MRCC and NCGC

(1) Effective January 1, 2023, Ms. Sheppard retired from the AIMCo Board of Directors.

(2) Denotes the year the individual became a Director of Emera. Directors are elected for a one year term which expires at the termination of Emera' s annual general meeting;

(3) Audit Committee (AC), Health, Safety and Environment Committee (HSEC), Management Resources and Compensation Committee (MRCC), Nominating and Corporate Governance Committee (NCGC), and Risk and Sustainability Committee (RSC);

(4) Ms. Sheppard is not a member of any committee but attends all committee meetings as Chair of the Board;

(5) Mr. Balfour is not a member of any committee as he is the President and Chief Executive Officer of the Company but attends all committee meetings.

Officers

The Officers of Emera as at December 31, 2023 were as follows:

Name and Residence	Principal Occupations During the Past Five Years
Scott C. Balfour President and Chief Executive Officer Halifax, Nova Scotia, Canada	A Director and President and Chief Executive Officer of Emera since March 29, 2018.(1)
Gregory W. Blunden, FCPA Chief Financial Officer Halifax, Nova Scotia, Canada	Chief Financial Officer of Emera since March 2016.
Karen E. Hutt Executive Vice-President, Business Development and Strategy Halifax, Nova Scotia, Canada	Executive Vice-President, Business Development and Strategy of Emera since October 21, 2019. Previously, President and Chief Executive Officer of NSPI since August 2016.
Bruce A. Marchand Chief Risk and Sustainability Officer Halifax, Nova Scotia, Canada	Chief Risk and Sustainability Officer of Emera since June 30, 2022. Prior to this Chief Legal and Compliance Officer of Emera and NSPI since December 1, 2014 and Chief Legal Officer of Emera and NSPI since January 2012.
R. Michael Roberts Chief Human Resources Officer Halifax, Nova Scotia, Canada	Chief Human Resources Officer of Emera and NSPI since December 1, 2014.
Daniel P. Muldoon Executive Vice-President Project Development and Operations Support Halifax, Nova Scotia, Canada	Executive Vice-President Project Development and Operations Support of Emera. Chair of the Boards of ENL, EBPC, Emera Technologies LLC and NMGC and Block Energy, LLC. Former Director of Emera Maine from August 2013 until March 2020. Director of TEC and NSPML. Formerly Executive Vice-President, Major Renewables and Alternative Energy since May 2014.
Michael R. Barrett Executive Vice-President and General Counsel Halifax, Nova Scotia, Canada	Executive Vice-President and General Counsel of Emera since July 1, 2022. Prior to this, General Counsel of Emera since November 20, 2017. Prior to joining Emera, Senior Partner and head of the power and climate change practice groups at Bennett Jones LLP in Toronto.
Brian C. Curry Corporate Secretary Halifax, Nova Scotia, Canada	Corporate Secretary of Emera since November 16, 2023 (2) and prior to that Associate Corporate Secretary, Emera. Former Senior Director Regulatory and Corporate Secretary, NSPI from February 2021 to February 2023, Senior Regulaory Counsel and Corporate Secretary, NSPI from January 1, 2020 to February 2021 and Regulatory Counsel from January 2015 to January 2020.

(1) Mr. Balfour' s principal occupations during the past five years are described above in the Directors table.

(2) Effective November 16, 2023, Mr. Brian C. Curry succeeded Mr. Stephen D. Aftanas as Corpoate Secretary. Effective January 31, 2024, Mr. Aftanas retired from Emera and various subsidiaries and/or subsidiary boards.

As at December 31, 2023, the Directors and Officers, in total, beneficially owned or controlled, directly or indirectly, 184,256 common shares or less than 1 per cent of the issued and outstanding common shares of Emera.

AUDIT COMMITTEE

The Audit Committee of Emera is composed of the following five members, all of whom are independent Directors: Kent M. Harvey (Chair), Paula Gold-Williams, B. Lynn Loewen, Ian E. Robertsonand Andrea S. Rosen. The responsibilities and duties of the Audit Committee are set out in the Audit Committee' s Charter, a copy of which is attached as Appendix "D" to this AIF.

The Board believes that the composition of the Audit Committee reflects a high level of financial literacy and experience. Each member of the Audit Committee has been determined by the Board to be "financially literate" as such term is defined under Canadian securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the Audit Committee. The following is a description of the education and experience of each member of the Audit Committee that is relevant to the performance of his or her responsibilities as a member of the Audit Committee:

Kent M. Harvey, Committee Chair

Former Chief Financial Officer for PG&E Corporation, an energy-based holding company headquartered in San Francisco. PG&E Corporation is the parent company of Pacific Gas and Electric Company, one of the largest combined natural gas and electric energy companies in the United States. In over 33 years with PG&E Corporation, Mr. Harvey held progressively senior roles before he retired in 2016, including Senior Vice President and Chief Financial Officer 2009 to 2015, Senior Vice President, Chief Risk and Audit Officer 2005 to 2009. He was Senior Vice President, Chief Financial Officer and Treasurer with Pacific Gas and Electric Company, a subsidiary of PG&E Corporation, from 2000 to 2005. He holds a Bachelor' s degree in Economics and a Master' s degree in Engineering, both from Stanford University.

Paula Y. Gold-Williams

She is the former President and CEO of CPS Energy, a fully integrated electric and natural gas municipal utility based in San Antonio, Texas. Ms. Gold-Williams served in positions of increasing responsibility at CPS Energy before becoming CEO in 2015. She held multiple other positions during her 17-year career at CPS Energy, including Group EVP – Financial & Administrative Services, CFO and Treasurer. Co-Chair of the Keystone Policy Center, having been a member of both the Policy Center and its Energy Board since 2016. Former Board member and Treasurer of EPIcenter, an innovation think tank; incubator and accelerator; and strategic advisory organization. She also serves on the US Secretary of Energy' s Advisory Board ("SEAB") and is a member of the board of directors of ReNew Energy Global Plc, a renewable energy company based in India. Formerly, First Vice Chair of the Electric Power Resource Institute (EPRI); a member and designated Chair Pro Tem of the Federal Reserve Bank of Dallas' San Antonio Branch; and a past-Chair of the San Antonio Chamber of Commerce. She holds an Associate Degree in Fine Arts from San Antonio College and a BBA in accounting from St. Mary' s University. She earned a Finance and Accounting MBA from Regis University in Denver, Colorado. She is a Certified Public Accountant and a Chartered Global Management Accountant.

B. Lynn Loewen, FCPA, FCA

Former President of Minogue Medical Inc., a Canadian supplier of innovative medical technologies, supplies and equipment. From 2008 to 2011, she was President of Expertech Network Installation Inc., a Canadian network infrastructure service provider and also held key positions with Bell Canada Enterprises, as Vice President of Finance Operations and Vice President of Financial Controls. Earlier in her career, she was with Air Canada Jazz where she held positions of increasing responsibility, including Vice President of Corporate Services and Chief Financial Officer. She is a member of the Board of Directors of National Bank of Canada, a Canadian Chartered Bank, Chair of its Audit Committee and member of its Technology Comittee. She was a member of the Board of Directors of Xplore Inc., a Canadian broadband service provider, and a member of its Audit Committee from 2021 to 2023. She is also a former member of the Public Sector Pension Investment Board where she served on the Audit and Conflicts Committee and as Audit Committee Chair. Chancellor of Mount Allison University and a member of the Executive Committee and Chair of its Nominating and Governance Committee since 2018. She was a member of the Board of Regents from 1998 to 2008, serving as Chair from 2007-2008. She holds a Bachelor of Commerce from Mount Allison University. Fellow of the Chartered Professional Accountants and has received the Institute of Corporate Directors, Directors Designation.

Ian E. Robertson

A principal of the Northern Genesis Capital Group, an investment group focused on identifying and acquiring energy transition businesses which demonstrate strong sustainability and Environmental, Social and Governance (ESG) alignment. Former CEO of Algonquin Power & Utilities Corp. (Algonquin Power), a publicly traded, diversified international generation, transmission, and distribution utility. Founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988 and predecessor organization to Algonquin Power. Over 30 years of experience in the development of electric power generating projects and the operation of diversified regulated utilities. Former Member of the Board of Directors of Northern Genesis Acquisition Corp., Northern Genesis Acquisition Corp. II and Northern Genesis Acquisition Corp. III and a former Director of Embark Technology, Inc., an autonomous vehicle company,Largo Resources Ltd., Algonquin Power and Atlantica Sustainable Infrastructure plc. Mr. Robertson is an electrical engineer and holds a Professional Engineering designation through his Bachelor of Applied Science degree awarded by the University of Waterloo. He earned a Master of Business Administration degree from York University' s Schulich School of Business. He holds a Chartered Financial Analyst designation, as well as a global professional Master of Laws degree from the University of Toronto. He received a Chartered Director designation from the Directors College of McMaster University. Mr. Robertson is a former member of the board of directors of the American Gas Association.

Andrea S. Rosen

Vice-Chair of TD Bank Financial Group and President, TD Canada Trust from 2002 to 2005. Prior to this, Executive Vice President of TD Commercial Banking and Vice Chair TD Securities. Before joining TD Bank, was Vice President of Varity Corporation from 1991 to 1994 and worked at Wood Gundy Inc. (later CIBC-Wood Gundy) in a variety of roles from 1981 to 1990, eventually becoming Vice President and Director. Holds a Bachelor of Laws from Osgoode Hall Law School and a Masters of Business Administration from the Schulich School of Business at York University. She received a Bachelor of Arts from Yale University. Ms. Rosen is a Director and member of the Audit Committee of Ceridian HCM Holding Inc., a global human capital management software company, and Director and member of the Audit Committee of Manulife Financial Corporation, an issuer listed on The Toronto Stock Exchange, New York Stock Exchange, The Stock Exchange of Hong Kong, and the Philippine Stock Exchange. She is a Director of Element Fleet Management Corp., a global fleet management company. Former Director and member of the Audit Committee of Hiscox Ltd., a Bermuda-incorporated specialty insurer listed on the London Stock Exchange, and former Director of Alberta Investment Management Corporation (“AIMCo.”). Former member of the Board of Directors of the Institute of Corporate Directors.

Audit and Non-Audit Services Pre-Approval Process

The Audit Committee is responsible for the oversight of the work of the external auditors. As part of this responsibility, the Audit Committee is required to pre-approve the audit and non-audit services performed by the external auditors in order to assure that they do not impair the external auditors' independence from the Company. Accordingly, the Audit Committee has adopted an Audit and Non-Audit Pre-Approval Policy, which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the external auditors may be pre-approved.

Unless a type of service has received the pre-approval of the Audit Committee, it will require specific approval by the Audit Committee if it is to be provided by the external auditors. Any proposed services exceeding the pre-approved cost levels will also require specific approval by the Audit Committee.

Auditors' Fees

The aggregate fees billed by Ernst & Young LLP, the Company' s external auditors, during the fiscal years ended December 31, 2023 and 2022 respectively, were as follows:

Service Fee	2023 ($)	2022 ($)
Audit Fees	$3,910,266	$2,018,989
Audit-Related Fees (1)	174,410	19,600
Tax Fees (2)	39,450	337,999
All Other Fees	75,000	–
Total	$4,199,126	$2,376,588

(1) Audit-related fees for Emera relate to fees associated with agreed upon procedures over rate-case filings and the audit of pension plans.

(2) Tax fees for Emera relate to tax compliance services and general tax consulting advice on various matters.

CERTAIN PROCEEDINGS

To the knowledge of Emera, none of the Directors or Officers of the Company:

(1) are, as at the date of this AIF, or have been, within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company that:

(a) was subject to an Order that was issued while the Director or Officer was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) was subject to an Order that was issued after the Director or Officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer of chief financial officer;

(2) are, as at the date of this AIF, or have been within ten years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;

(3) have, within the ten years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed nominee; or

(4) have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory body or has entered in a settlement agreement with a securities regulatory body, or is subject to any penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

CONFLICTS OF INTEREST

There are no existing or potential material conflicts of interest between Emera or any of its subsidiaries and any Director or Officer of Emera or any of its subsidiaries.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of Emera, there are no legal proceedings that individually or together could potentially involve claims against Emera or its subsidiaries for damages totaling 10 per cent or more of the current assets of Emera, exclusive of interest and costs.

During Emera's most recently completed financial year, there have been no (a) penalties or sanctions imposed against Emera by a court relating to securities legislation or by a securities regulatory authority, (b) other penalties or sanctions imposed by a court or regulatory body against Emera that would likely be considered important to a reasonable investor in making an investment decision, and (c) settlement agreements entered into by Emera before a court relating to securities legislation or with a securities regulatory authority.

NO INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the following persons or companies, namely (a) a Director or Officer of Emera, (b) a person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10 per cent of any class or series of Emera's outstanding voting securities, or (c) an associate or affiliate of any person or company named in (a) or (b), had a material interest in any transaction involving Emera within Emera's last three completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Emera.

MATERIAL CONTRACTS

Emera did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2023, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2023 that are still in effect as at the date of this AIF.

TRANSFER AGENT AND REGISTRAR

TSX Trust Company acts as Emera's transfer agent and registrar for Emera's common shares and first preferred shares. Registers for the registration and transfer of these securities of Emera are kept at TSX Trust Company's principal offices in Halifax, Montreal and Toronto.

EXPERTS

Ernst & Young LLP are the external auditors of Emera. Ernst & Young LLP report that they are independent in the context of the CPA Code of Professional Conduct of the Chartered Professional Accountants of Nova Scotia and are in compliance with Rule 3520 of the Public Company Accounting Oversight Board (United States).

ADDITIONAL INFORMATION

Additional information relating to Emera may be found on SEDAR+ at www.sedarplus.ca or upon request to the Corporate Secretary, Emera Incorporated, P.O. Box 910, Halifax, N.S., B3J 2W5, telephone (902) 428-6096 or fax (902) 428-6171. Additional information, including Directors' and Officers' remuneration and indebtedness, principal holders of Emera's securities and securities authorized for issuance under equity compensation plans, is contained in Emera's information circular for the most recent annual meeting of Emera's common shareholders. Additional financial information is provided in Emera's Audited Financial Statements and MD&A.

At any time, Emera will provide to any person upon request to the Corporate Secretary, a copy of the Emera Code of Conduct. Alternatively, a copy of the Emera Code of Conduct is available electronically under Emera's profile on SEDAR+ at www.sedarplus.ca and on its corporate website at www.emera.com.

For convenience, certain terms used throughout this AIF shall have the following meanings:

“**adjusted net income**” has the meaning ascribed to it in the “Non-GAAP Financial Measures and Ratios” section of the MD&A, which is incorporated herein by reference, a copy of which is available electronically under Emera’ s profile on SEDAR+ at www.sedarplus.ca;

“**AFUDC**” means allowance for funds used during construction and represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment, where permitted by the regulator;

“**AIF**” or “**Annual Information Form**” means this 2023 Annual Information Form of Emera;

“**Atlantic Canada**” means the region of Canada consisting of the Provinces of New Brunswick, Newfoundland and Labrador, Nova Scotia and Prince Edward Island;

“**ATM Program**” means an at-the-market distribution program allowing Emera to issue common shares from treasury at the prevailing market price.

“**Audited Financial Statements**” means the audited consolidated financial statements of Emera as at and for the years ended December 31, 2023 and December 31, 2022, together with the auditors’ report thereon, a copy of which is available electronically under Emera’ s profile on SEDAR+ at www.sedarplus.ca;

“**Bahamas DRs**” means the DRs listed on BISX;

“**Barbados DRs**” means the DRs listed on the BSE;

“**BBD**” means Barbadian dollars;

“**BISX**” means The Bahamas International Securities Exchange;

“**Bear Swamp**” means Bear Swamp Power Company, LLC, a 633 MW pumped storage hydroelectric company incorporated under the laws of the State of Delaware in which Emera indirectly holds a 50 per cent interest;

“**Block Energy**” means Block Energy LLC, formerly Emera Technologies LLC, a wholly-owned subsidiary of Emera existing under the laws of the State of Florida.

“**BLPC**” means Barbados Light & Power Company Limited, a vertically integrated electric utility company incorporated under the laws of Barbados and a wholly-owned, direct subsidiary of ECI;

“**Board**” means the Board of Directors of Emera;

“**Brooklyn Energy**” means Brooklyn Power Corporation, a 30 MW biomass co-generation company incorporated under the laws of the Province of Nova Scotia and a wholly-owned direct subsidiary of Emera;

“**Brunswick Pipeline**” means the pipeline delivering re-gasified natural gas from the Saint John LNG gas terminal near Saint John, New Brunswick to markets in the Northeastern United States, which is owned directly by EBPC;

“**BSD**” means Bahamian dollars;

“**BSE**” means the Barbados Stock Exchange;

“**CAD**” means Canadian dollars;

“**CAIR**” means the Clean Air Interstate Rule;

“**CER**” or “**Canada Energy Regulator**”, the independent regulator of EBPC.

“**COMFIT**” means the Nova Scotia Community Feed in Tariff program which is offered by the Province of Nova Scotia and enables community organizations to be involved in renewable electricity generation;

“**Company**” means Emera;

“**Consolidated Balance Sheets**” means the consolidated balance sheets contained within the Audited Financial Statements;

“**Directors**” mean the directors of Emera and “**Director**” means any one of them;

“**Dividend Reinvestment Plan**” or “**DRIP**” means the Company’ s Common Shareholders’ Dividend Reinvestment and Share Purchase Plan;

“**DR**” means a depositary receipt representing common shares of Emera;

“**EBPC**” or “**Emera Brunswick Pipeline Company**” means Emera Brunswick Pipeline Company Ltd., a company incorporated under the federal laws of Canada and a wholly-owned, indirect subsidiary of Emera;

“**ECI**” means Emera (Caribbean) Incorporated, a company incorporated under the laws of Barbados and an indirect subsidiary of Emera and the parent company of BLPC and GBPC;

“**ECRC**” means the environmental cost recovery clause;

"**Electricity Act**" means the *Electricity Act, 2004, c. 25, s. 1.* (Nova Scotia);

"**Emera**" means Emera Incorporated, a public company incorporated under the laws of the Province of Nova Scotia and traded on the TSX under the symbol "EMA";

"**Emera Energy**" means the businesses of Emera Energy Services, Brooklyn Energy and Bear Swamp;

"**Emera Energy LP**" means a wholly-owned subsidiary of Emera formed under the laws of the Province of Nova Scotia;

"**Emera Energy Services**" or "**EES**" means Emera Energy LP and Emera Energy Services, Inc., a natural gas and electricity marketing and trading company and a wholly-owned, indirect subsidiary of Emera incorporated under the laws of the State of Delaware, which together form a natural gas and electricity marketing and trading business;

"**ENL**" **or** "**Emera Newfoundland and Labrador**" means Emera Newfoundland and Labrador Holdings Incorporated, a company incorporated under the laws of the Province of Newfoundland and Labrador and a wholly-owned, direct subsidiary of Emera, and the parent company of NSP Maritime Link Inc. and ENL Island Link Inc.;

"**ENL Island Link Inc.**" means ENL Island Link Incorporated, a company incorporated under the laws of the Province of Newfoundland and Labrador and a wholly-owned, direct subsidiary of ENL;

"**EPA**" means the U.S. Environmental Protection Agency;

"**Fair Trading Commission, Barbados**" or "**FTC**" means the regulator of BLPC;

"**FAM**" means the fuel adjustment mechanism established by the UARB;

"**FCM**" means forward capacity market;

"**FERC**" means the United States Federal Energy Regulatory Commission;

"**Fitch**" means the credit rating agency Fitch Ratings Inc;

"**First Preferred Shares**" means each series of Emera' s authorized first preferred shares, namely its Series 2016-A Conversion, First Preferred Shares, Series A First Preferred Shares, Series B First Preferred Shares, Series C First Preferred Shares, Series D First Preferred Shares, Series E First Preferred Shares, Series F First Preferred Shares, Series G First Preferred Shares Series H First Preferred Shares, Series I First Preferred Shares Series J First Preferred Shares and Series L First Preferred Shares;

"**FPSC**" means the Florida Public Service Commission, the regulator of Tampa Electric and PGS;

"**GBPA**" means The Grand Bahama Port Authority, the regulator of GBPC;

"**GBPC**" or "**Grand Bahama Power Company**" means Grand Bahama Power Company Limited, a vertically integrated electric utility company incorporated under the laws of the Commonwealth of The Bahamas and an indirect subsidiary of ECI;

"**Government of Canada Bond Yield**" on any date means the yield to maturity on such date (assuming semi-annual compounding) of a Canadian dollar denominated non-callable Government of Canada bond with a term to maturity of five years as quoted as of 10:00 a.m. (Toronto time) on such date and which appears on the Bloomberg Screen GCAN5YR Page on such date; provided that, if such rate does not appear on the Bloomberg Screen GCAN5YR Page on such date, the Government of Canada Bond Yield will mean the average of the yields determined by two registered Canadian investment dealers selected by the Company as being the yield to maturity on such date (assuming semi-annual compounding) which a Canadian dollar denominated non-callable Government of Canada bond would carry if issued in Canadian dollars at 100 per cent of its principal amount on such date with a term to maturity of five years;

"**Government of Canada T-Bill Rate**" means, for any quarterly floating rate period, the average yield expressed as a percentage per annum on three month Government of Canada treasury bills, as reported by the Bank of Canada, for the most recent treasury bills auction preceding the applicable floating rate calculation date;

"**GWh**" means the amount of electricity measured in gigawatt hours;

"**Hybrid Notes**" means the $1.2 billion USD unsecured, fixed-to-floating subordinated notes of Emera due 2076;

"**IFRS**" means International Financial Reporting Standards;

"**IMP**" means integrity management programs;

"**IPPs**" means independent power producers;

"**km**" means kilometre(s);

"**Labrador-Island Transmission Link Project**" or "**LIL**" means an electricity transmission project in Newfoundland and Labrador being developed by Nalcor, which will enable the transmission of the

Muskrat Falls energy between Labrador and the island of Newfoundland;

"**LNG**" means liquefied natural gas;

"**Lucelec**" means St. Lucia Electricity Services Limited, a company incorporated under the laws of St. Lucia in which Emera holds an indirect 19.5 per cent interest through ECI;

"**M&NP**" means the Maritimes & Northeast Pipeline, a pipeline that transports natural gas between the Maritime Provinces and New England, in which Emera holds an indirect 12.9 per cent interest;

"**Maritime Link**" means the transmission project which includes two 170-km sub-sea cables between the island of Newfoundland and the Province of Nova Scotia, developed by NSP Maritime Link Inc.;

"**Maritime Provinces**" means the region of Canada consisting of the Provinces of Nova Scotia, New Brunswick and Prince Edward Island;

"**MD&A**" means Emera' s Management' s Discussion and Analysis for the fiscal year ended December 31, 2023, a copy of which is available electronically under Emera' s profile on SEDAR+ at www.sedarplus.ca;

"**Moody' s**" means the credit rating agency Moody' s Investor Services, Inc. a subsidiary of Moody' s Corporation;

"**MW**" means the amount of power measured in megawatts;

"**Nalcor**" means Nalcor Energy, a company that is incorporated under a special act of the Legislature of the Province of Newfoundland and Labrador as a Crown corporation;

"**NB Power**" means New Brunswick Power Corporation, a provincial Crown corporation formed under the laws of the Province of New Brunswick, responsible for the generation, transmission and distribution of electricity in the Province of New Brunswick;

"**NERC**" means North American Electric Reliability Corporation;

"**New England**" means the region of the United States consisting of the States of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont;

"**NMGC**" means New Mexico Gas Company, Inc., a regulated gas distribution utility incorporated under the laws of Delaware and serving customers across New Mexico;

"**NMPRC**" means the New Mexico Public Regulation Commission, the regulator of NMGC;

"**NPCC**" means Northeast Power Coordinating Council, Inc.;

"**Northeastern United States**" means the region of the United States consisting of New England and the States of New Jersey, New York and Pennsylvania;

"**NS Block**" means the electricity transmitted through the Maritime Link from the Muskrat Falls hydroelectric project

"**NSP Maritime Link Inc.**" or "**NSPML**" means NSP Maritime Link Incorporated, a wholly-owned direct subsidiary of ENL, incorporated under the laws of the Province of Newfoundland and Labrador, that developed the Maritime Link;

"**NSPI**" or "**Nova Scotia Power**" means Nova Scotia Power Incorporated, a vertically integrated electric utility incorporated under the laws of the Province of Nova Scotia and a wholly-owned direct and indirect subsidiary of Emera;

"**Officers**" mean the executive officers of Emera and "**Officer**" means any one of them;

"**OM&G**" means operating, maintenance and general;

"**OBPS**" means output-based pricing system;

"**Order**" means a cease trade order, an order similar to a cease trade order or an order that denies a company access to any exemption under securities legislation that is in effect for a period of more than 30 consecutive days;

"**PGAC**" means purchased gas adjustment clause;

"**PGS**" or "**Peoples Gas System**" means Peoples Gas System, Inc., formerly the Peoples Gas System Division of TEC, operating as a regulated gas distribution utility serving customers across Florida , and a wholly-owned direct subsidiary of TECO Gas Operations, Inc. existing under the laws of the State of Florida;

"**PP&E**" means property, plant and equipment;

"**Privatization Act**" means the Nova Scotia Power Privatization Act, S.N.S., 1992, c.8 - and all amendments thereto;

"**Province**" means the Province of Nova Scotia, Canada and includes, when the context requires, the provincial government of Nova Scotia, and "provincial" refers to Nova Scotia;

"**Public Utilities Act**" means the *Public Utilities Act* (Nova Scotia);

"**Rating Agencies**" means collectively Fitch, Moody' s and S&P, and "**Rating Agency**" means any one of the Rating Agencies;

"**RENAC**" means Repsol Energy North America Canada Partnership;

"**Reorganization Act**" means the Nova Scotia Power Reorganization (1998) Act, S.N.S., 1998, c.19 - and all amendments thereto;

"**Repsol**" means Repsol S.A, the parent company of RENAC;

"**RER**" means the Nova Scotia Renewable Electricity Regulations;

"**ROE**" means return on equity;

"**S&P**" means the credit rating agency S&P Global Ratings, a division of S&P Global Inc.;

"**SeaCoast**" means SeaCoast Gas Transmission, LLC, a company incorporated under the laws of the State of Delaware and a wholly-owned subsidiary of TECO Energy;

"**Securities Act**" means the *United States Securities Act of 1933*, as amended;

"**SEDAR+**" means the secure web-based system used by all market participants to file, disclose and search for information in Canada' s capital markets, which can be found at www.sedarplus.ca, and replaces SEDAR, the System for Electronic Documents Analysis and Retrieval;

"**Series 2016-A Conversion, First Preferred Shares**" means the cumulative preferential first preferred shares, Series 2016-A of Emera;

"**Series A First Preferred Shares**" means the cumulative 5-year rate reset first preferred shares, Series A of Emera;

"**Series B First Preferred Shares**" means the cumulative floating rate first preferred shares, Series B of Emera;

"**Series C First Preferred Shares**" means the cumulative rate reset first preferred shares, Series C of Emera;

"**Series D First Preferred Shares**" means the cumulative floating rate first preferred shares, Series D of Emera;

"**Series E First Preferred Shares**" means the cumulative redeemable first preferred shares, Series E of Emera;

"**Series F First Preferred Shares**" means the cumulative rate reset first preferred shares, Series F of Emera;

"**Series G First Preferred Shares**" means the cumulative floating rate first preferred shares, Series G of Emera;

"**Series H First Preferred Shares**" means the cumulative minimum rate reset first preferred shares, Series H of Emera;

"**Series I First Preferred Shares**" means the cumulative floating rate first preferred shares, Series I of Emera;

"**Series J First Preferred Shares**" means the cumulative minimum rate reset first preferred shares, Series J of Emera;

"**Series K First Preferred Shares**" means the cumulative floating rate first preferred shares, Series K of Emera;

"**Series L First Preferred Shares**" means the cumulative redeemable first preferred shares, Series L of Emera;

"**SO_2**" means sulphur dioxide;

"**SoBRA**" means solar base rate adjustment;

"**TEC**" means Tampa Electric Company, an integrated regulated electric utility, serving customers in West Central Florida, a wholly-owned subsidiary of TECO Energy, incorporated under the laws of the State of Florida ;

"**TECO Energy**" means TECO Energy, Inc., an energy-related holding company incorporated under the laws of the State of Florida with regulated electric and gas utilities in Florida and a regulated gas utility in New Mexico;

"**TECO Gas Operations, Inc.**" means the wholly-owned subsidiary of TECO Energy, incorporated under the laws of the State of Florida, and the parent company of PGSI, which as of January 1, 2023, currently owns the regulated gas utility known as PGS, formerly a division of TEC;

"**TSX**" means The Toronto Stock Exchange;

"**UARB**" means the Nova Scotia Utility and Review Board, the independent regulator of NSPI;

"**USD**" means U.S. dollars; and

"**USGAAP**" means the accounting principles which are recognized as being generally accepted and which are in effect from time to time in the U.S. as codified by the Financial Accounting Standards Board, or any successor institute.

APPENDIX "B" ‑ Summary of Terms and Conditions of Authorized Series of First Preferred Shares

As of December 31, 2023, the following series of First Preferred Shares have been authorized:

Series A, B, C, D, E, F, G, H, I, J, K and L First Preferred Shares

Holders of the First Preferred Shares are not entitled to attend any meetings of the shareholders of Emera or to vote at any such meeting, except: (i) where entitled by law; (ii) for meetings of the holders of first preferred shares as a class and holders of First Preferred Shares as a series; and (iii) in situations when Emera fails to pay, in the aggregate, eight quarterly dividends on the First Preferred Shares.

In any instance where the holders of First Preferred Shares are entitled to vote, each holder shall have one vote for each Preferred Share, subject to the restrictions described under "Share Ownership Restrictions" below.

Holders of Series A, C, F, H and J First Preferred Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, to be reset periodically on established dates to an annualized rate equal to the sum of the then five-year Government of Canada Bond Yield, calculated at the start of the applicable five-year period, and a spread as set forth in the table below (subject, (i) in the case of the Series H preferred shares, to a fixed minimum reset of 4.90 per cent and (ii) in the case of the Series J preferred shares, to a fixed minimum reset of 4.25 per cent). Holders of the Series A, C, F, H and J First Preferred Shares have the right to convert their shares into an equal number of Series B, D, G, I and K First Preferred Shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below.

Holders of Series B, D, G, I and K First Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board. The dividends are payable quarterly, in the amount per share determined by multiplying the applicable quarterly floating dividend rate, which is the sum of the three-month Government of Canada T-Bill Rate , recalculated quarterly, on the applicable reset date plus a spread as set forth in the table below.

The Series A, C, F, H and J First Preferred Shares are redeemable by Emera, in whole or in part under certain circumstances by the payment of cash on the dates set forth in the table below at a price of $25.00 per share plus any accrued and unpaid dividends.

The Series B, D, G, I and K First Preferred Shares are redeemable by Emera, in whole or in part under certain circumstances after their respective initial redemption dates by payment in cash as set forth in the table below at a price equal to (i) $25.00 per share together with all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions as set out in the table below or (ii) $25.50 per share together with all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date.

Subject to certain conditions including the right of Emera to redeem, holders of the Series A, C, F, H and J First Preferred Shares, have the right to convert any or all of their Series A, C, F, H and J First Preferred Shares into an equal number of Series B, D, G, I and K First Preferred Shares, respectively. In addition, the Series A, C, F, H and J First Preferred Shares may be automatically converted by Emera into Series B, D, G, I and K First Preferred Shares, respectively if Emera determines that, following conversion by the holders, there would be less than 1,000,000 Series A, C, F, H and J First Preferred Shares outstanding, respectively.

Subject to automatic conversion conditions including the right of Emera to redeem the Series B, D, G, I and K First Preferred Shares, the holders of Series B, D, G, I and K First Preferred Shares have the right to convert any or all of their Series B, D, G, I and K First Preferred Shares into an equal number of Series A, C, F, H and J First Preferred Shares respectively. In addition, Series B, D, G, I and K First Preferred Shares may be automatically converted by Emera into Series A, C, F, H and J First Preferred Shares, respectively if Emera determines that, following conversion by the holders, there would be less than 1,000,000 Series B, D, G, I and K First Preferred Shares outstanding.

Holders of Series E First Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board in the amount of $1.125 per share per annum in perpetuity, subject to certain redemption rights. The Series E First Preferred Shares were not redeemable by the Company prior to August 18, 2018. The Series E First Preferred Shares are redeemable on or after August 18, 2018 by Emera in whole or in part, at the Company' s option without the consent of the holder, by the payment of: $26.00 per share if redeemed before August 15, 2019; $25.75 per share if redeemed on or after August 15, 2019 but before August 15, 2020; $25.50 per share if redeemed on or after August 15, 2020 but before August 15, 2021; $25.25 per share if redeemed on or after August 15, 2021 but before August 15, 2022; and $25.00 per share if redeemed on or after August 15, 2022; together, in each case, with all accrued and unpaid dividends up to but excluding the date fixed for redemption.

Holders of Series L First Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board in the amount of $1.150 per share per annum in perpetuity, subject to certain redemption rights. The Series L First Preferred Shares were not redeemable by the Company prior to November 15, 2026. The Series L First Preferred Shares are redeemable on or after November 15, 2026 by Emera in whole or in part, at the Company' s option without the consent of the holder, by the payment of: $26.00 per share if redeemed before November 15, 2027; $25.75 per share if redeemed on or after November 15, 2027 but before November 15, 2028; $25.50 per share if redeemed on or after November 15, 2028 but before November 15, 2029; $25.25 per share if redeemed on or after November 15, 2029 but before November 15, 2030; and $25.00 per share if redeemed on or after November 15, 2030; together, in each case, with all accrued and unpaid dividends up to but excluding the date fixed for redemption.

Applicable redemption, conversion, interest and reset dates and spreads are listed in the following table:

Series of First Preferred Shares	Initial Redemption / Interest Reset Date	Subsequent Redemption / Conversion / Interest Reset Dates	Spreads
Series A	August 15, 2015	August 15, 2020 and every fifth year thereafter	1.84%
Series B	August 15, 2020	August 15, 2025 and every fifth year thereafter	1.84%
Series C	August 15, 2018	August 15, 2023 and every fifth year thereafter	2.65%
Series D	–	August 15, 2023 and every fifth year thereafter	2.65%
Series E	August 15, 2018	–	–
Series F	February 15, 2020	February 15, 2025 and every fifth year thereafter	2.63%
Series G	–	February 15, 2025 and every fifth year thereafter	2.63%
Series H	August 15, 2023	August 15, 2028 and every fifth year thereafter	2.54%
Series I	–	August 15, 2028 and every fifth year thereafter	2.54%
Series J	May 15, 2026	May 15, 2031 and every fifth year thereafter	3.28%
Series K	–	May 15, 2031 and every fifth year thereafter	3.28%
Series L	November 15, 2026	–	–

Series 2016-A Conversion, First Preferred Shares

The Series 2016-A Conversion, First Preferred Shares were authorized pursuant to the Hybrid Notes offering in June 2016. As at December 31, 2023, there were no Series 2016-A Conversion, First Preferred Shares issued and outstanding.

Holders of Series 2016-A Conversion, First Preferred Shares are not entitled to attend any meetings of the shareholders of Emera or to vote at any such meeting, except: (i) where entitled by law; (ii) for meetings of the holders of first preferred shares as a class and holders of Series 2016-A Conversion, First Preferred Shares as a series; and (iii) in situations when Emera fails to pay, in the aggregate, eight quarterly dividends on the Series 2016-A Conversion, First Preferred Shares.

In any instance where the holders of Series 2016-A Conversion, First Preferred Shares are entitled to vote, each holder shall have one vote for each Series 2016-A Conversion, First Preferred Share, subject to the restrictions described under "Share Ownership Restrictions" below.

Holders of each series of Series 2016-A Conversion, First Preferred Shares will be entitled to receive cumulative preferential cash dividends, if, as and when declared by the Board, at the same rate as would have accrued on the related series of Hybrid Notes (had such Hybrid Notes remained outstanding). The Series 2016-A Conversion, First Preferred Shares do not have a fixed maturity date.

The Series 2016-A Conversion, First Preferred Shares are redeemable by Emera on June 15, 2026. After that date, Emera may redeem at any time all, or from time to time any part, of the outstanding Series 2016-A Conversion, First Preferred Shares, without the consent of the holders, by the payment of an amount in cash for each such share so redeemed of USD$1,000 per share together with an amount equal to all accrued and unpaid dividends thereon.

APPENDIX "C" - MONTHLY TRADING VOLUME AND HIGH AND LOW PRICE FOR EMERA' S SECURITIES IN 2023

	Common Shares	Depositary Receipts		Series of First Preferred Shares							
		Barbados BBD (1)	Bahamas BSD (2)	A	B	C	E	F	H	J	L
December											
High ($)	50.55	18.83	9.42	14.00	15.70	20.45	16.94	17.47	21.90	18.25	17.05
Low ($)	47.33	17.40	8.70	13.20	14.76	19.32	16.11	16.62	19.75	17.50	16.30
Volume	19,145,916	0	0	81,163	24,431	228,024	57,698	214,705	215,190	244,386	267,602
November											
High ($)	49.21	23.00	8.97	13.91	15.95	20.60	17.10	17.50	21.80	18.49	17.41
Low ($)	45.45	16.21	8.19	12.72	15.06	18.14	15.20	15.60	18.98	16.19	15.23
Volume	28,093,789	82	0	148,350	10,561	178,388	37,638	381,774	188,378	218,322	305,514
October											
High ($)	48.84	23.00	8.94	13.75	16.39	19.32	16.28	17.17	19.93	17.63	16.40
Low ($)	43.67	15.94	7.97	12.75	15.21	17.94	14.99	15.57	18.30	16.00	15.10
Volume	36,544,687	76	0	101,371	30,259	125,041	70,245	41,159	144,040	195,141	147,818
September											
High ($)	52.31	23.00	9.69	13.12	15.75	19.70	16.69	16.83	20.34	18.50	16.78
Low ($)	47.32	17.43	8.75	13.01	15.02	19.00	15.94	16.25	19.51	17.01	16.06
Volume	18,371,308	192	0	11,087	11,445	151,253	62,159	51,754	113,419	101,830	129,228
August											
High ($)	53.53	25.00	10.10	13.60	17.00	20.74	16.95	17.55	21.49	20.89	17.00
Low ($)	50.04	18.35	10.10	13.03	15.50	19.01	16.39	16.47	19.41	18.04	16.01
Volume	22,784,822	35	1,000	37,109	13,238	280,632	34,752	78,393	219,728	135,859	80,944
July											
High ($)	55.74	25.00	10.54	13.62	17.96	20.95	17.15	17.64	22.90	21.73	17.35
Low ($)	52.41	19.54	9.88	13.18	15.97	20.10	16.80	17.02	20.48	20.58	16.85
Volume	20,071,924	201	0	113,886	52,124	165,331	60,766	81,152	132,309	138,081	108,285
June											
High ($)	56.75	25.00	10.56	13.30	15.97	20.74	17.65	17.84	21.65	22.08	18.15
Low ($)	52.96	19.97	9.99	12.49	14.21	18.90	16.75	17.10	20.24	20.89	16.91
Volume	15,758,704	30	0	91,735	17,410	208,315	29,981	40,398	127,602	58,313	30,399
May											
High ($)	59.52	25.00	11.03	13.42	15.35	19.42	18.25	18.30	21.02	22.76	18.49
Low ($)	55.57	20.30	10.21	12.54	14.50	18.40	17.27	16.99	20.19	21.04	17.57
Volume	27,608,566	509	0	121,371	38,700	79,745	31,981	222,314	77,556	57,454	67,226
April											
High ($)	59.16	21.73	10.86	13.60	16.05	19.60	18.50	17.84	20.86	23.10	19.03
Low ($)	54.67	20.34	10.17	13.21	15.25	18.67	17.74	17.45	20.00	22.10	18.00
Volume	27,990,485	0	0	39,553	25,220	79,168	33,017	431,011	90,965	55,156	100,356
March											
High ($)	56.59	20.91	10.45	14.20	16.43	20.26	19.08	18.31	21.87	23.25	18.85
Low ($)	51.94	19.07	9.54	13.03	15.56	18.66	17.82	16.82	20.04	21.33	18.05
Volume	23,800,570	0	0	136,683	19,660	158,448	58,620	64,854	96,223	109,043	78,142
February											
High ($)	55.50	20.48	9.60	14.17	16.50	20.05	19.07	18.55	23.45	24.53	19.27
Low ($)	52.36	19.65	9.60	13.76	16.00	19.51	18.06	17.96	21.25	22.85	18.40
Volume	30,781,125	0	210	36,325	16,498	134,376	62,935	68,619	78,081	63,862	70,049
January											
High ($)	55.31	20.58	10.29	14.24	16.50	20.45	19.10	18.81	22.80	23.86	19.28
Low ($)	51.00	18.80	9.40	13.49	15.05	18.60	16.97	17.47	20.95	21.82	17.20
Volume	28,195,557	0	0	88,141	20,360	92,940	46,564	43,481	83,125	69,677	108,678

(1) The Barbados DRs trade on the BSE. During those months in 2023 when the Volume Traded was zero (0), the table above indicates the high and low trading prices of the Barbados DRs relative to those of Emera' s common shares on the TSX.

(2) The Bahamas DRs trade on the BISX. During those months in 2023 when the Volume Traded was zero (0), the table above indicates the high and low trading prices of the Bahamas DRs relative to those of Emera' s common shares on the TSX.

APPENDIX “D” - EMERA INCORPORATED AUDIT COMMITTEE CHARTER

PART I
MANDATE AND RESPONSIBILITIES

Committee Purpose

There shall be a committee of the Board of Directors (the “Board”) of Emera Inc. (“Emera”) which shall be known as the Audit Committee (the “Committee”). The Committee shall assist the Board in discharging its oversight responsibilities concerning:

- *the quality and integrity of Emera’s financial statements;*
- *the effectiveness of Emera’s internal control systems over financial reporting;*
- *the internal audit and assurance process;*
- *the qualifications, independence and performance of the external auditors;*
- *major financial risk exposures;*
- *Emera’s compliance with legal requirements and securities regulations in respect of financial statements and financial reporting; and*
- *any other duties set out in this Charter or delegated to the Committee by the Board.*

1. Financial Reporting

(a) The Committee shall be responsible for reviewing, assessing the completeness and clarity of the disclosures in, and recommending to the Board for approval:

(i) the audited annual financial statements of Emera, all related Management’s Discussion and Analysis, and earnings press releases;

(ii) any documents containing Emera’s audited financial statements; and,

(iii) the quarterly financial statements, all related Management’s Discussion and Analysis, and earnings press releases.

(b) The Board may delegate the approval of the quarterly financial statements, all related Management’s Discussion and Analysis, and earnings press releases to the Committee.

(c) The Committee shall oversee and assess that adequate procedures are in place for the review of public disclosure of financial information.

2. External Auditors

(a) The Committee shall evaluate and recommend to the Board the external auditor to be nominated for the purpose of preparing or issuing the auditor’s report or performing other audit, review, or attest services for Emera, and the compensation of such external auditors.

(b) Once appointed, the external auditor shall report directly to the Committee, and the Committee shall oversee the work of the external auditor concerning the preparation or issuance of the auditor' s report or the performance of other audit, review or attest services for Emera.

(c) The Committee shall be responsible for resolving disagreements between management and the external auditor concerning financial reporting.

(d) At least annually, the Committee shall obtain and review a report by the external auditors describing: (i) the firm' s internal quality control procedures; (ii) any material issues raised by the most recent internal quality control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, with respect to one or more external audits carried out by the firm, and any steps taken to deal with any such issues; and (iii) all relationships between the external auditors and Emera (to assess the auditors' independence).

(e) The Committee shall annually evaluate the auditors' , including the lead audit partner' s, qualifications, performance, professional skepticism and independence.

(f) The Committee shall determine that the external audit firm has a process in place to address the rotation of the lead audit partner and other audit partners serving the account as required under prescribed independence rules.

(g) Every five (5) years, the Committee shall perform a comprehensive review of the performance of the external auditors over multiple years to provide further insight on the audit firm, its independence and application of professional standards.

(h) The Committee will review differences that were noted or proposed by the external auditors, but that were considered immaterial or insignificant; and any "management" or "internal control" letter issued, or proposed to be issued.

3. Non-Audit Services

(a) The Committee shall be responsible for reviewing and pre-approving all non-audit services to be provided to Emera, or any of its subsidiaries, by the external auditor.

(b) The Committee may establish specific policies and procedures concerning the performance of non-audit services by the external auditor so long as the requirements of applicable legislation and regulation are satisfied.

(c) In accordance with policies and procedures established by the Committee, and applicable legislation and regulation, the Committee may delegate the pre-approval of non-audit services to a member of the Committee or a sub-committee thereof.

4. Oversight and Monitoring of Audits

(a) The Committee shall meet with the external auditor prior to the audit to discuss the planning and staffing of the audit, including the general approach, scope, areas subject to significant risk of material misstatement, estimated fees and other terms of engagement.

(b) The Committee shall discuss with the external auditor any issues that arise with Management or the internal auditors during the course of the audit and the adequacy of Management' s responses in addressing audit-related deficiencies.

(c) The Committee shall regularly review with the external auditors any audit problems or difficulties encountered during the course of the audit work, including any restrictions on the scope of the external auditors' activities or access to requested information, and Management' s response.

(d) The Committee shall review with Management the results of internal and external audits.

(e) The Committee shall take such other reasonable steps as it may deem necessary to oversee that the audit was conducted in a manner consistent with applicable legal requirements and auditing standards of applicable professional or regulatory bodies.

5. Oversight and Review of Accounting Principles and Practices

The Committee shall oversee, review and discuss with Management, the external auditor and the internal auditors:

(a) the quality, appropriateness and acceptability of Emera' s accounting principles and practices used in its financial reporting, changes in Emera' s accounting principles or practices and the application of particular accounting principles and disclosure practices by Management to new transactions or events;

(b) all significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including the effects of alternative methods within generally accepted accounting principles on the financial statements and any "other opinions" sought by Management from an independent auditor, other than the Company' s external auditors, with respect to the accounting treatment of a particular item, and other material written communications between the external auditors and management;

(c) disagreements between Management and the external auditor or the internal auditors regarding the application of any accounting principles or practices;

(d) any material change to Emera' s auditing and accounting principles and practices as recommended by Management, the external auditor or the internal auditors or which may result from proposed changes to applicable generally accepted accounting principles;

(e) the effect of regulatory and accounting initiatives on Emera' s financial statements and other financial disclosures;

(f) any reserves, accruals, provisions, estimates or Management programs and policies, including factors that affect asset and liability carrying values and the timing of revenue and expense recognition, that may have a material effect upon the financial statements of Emera;

(g) the use of special purpose entities and the business purpose and economic effect of off-balance sheet transactions, arrangements, obligations, guarantees and other relationships of Emera and their impact on the reported financial results of Emera;

(h) any legal matter, claim or contingency that could have a significant impact on the financial statements, Emera' s compliance policies and any material reports, inquiries or other correspondence received from regulators or governmental agencies and the manner in which any such legal matter, claim or contingency has been disclosed in Emera' s financial statements;

(i) the treatment for financial reporting purposes of any significant transactions which are not a normal part of Emera' s operations.

6. Hiring Policies

The Committee shall review and approve Emera' s hiring policy concerning partners or employees, as well as former partners and employees, of the present or former external auditors of Emera.

7. Pension Plans

The Committee shall exercise oversight of the pension plans in accordance with the Pension Oversight Framework adopted by Emera.

8. Oversight of Finance Matters

(a) The Committee shall review the appointments of key financial executives involved in the financial reporting process of Emera, including the Chief Financial Officer.

(b) The Committee may request for review, and shall receive when requested, material tax policies and tax planning initiatives, tax payments and reporting and any pending tax audits or assessments. The Committee shall review Emera' s compliance with tax and financial reporting laws and regulations.

(c) The Committee shall meet at least annually with Management to review and discuss Emera' s major financial risk exposures and the policy steps Management has taken to monitor and control such exposures, including the use of financial derivatives, hedging activities, and credit and trading risks.

(d) The Committee may review any investments or transactions that the Committee wishes to review, or which the internal or external auditor, or any officer of Emera, may bring to the attention of the Committee within the context of this charter.

(e) The Committee shall review financial information of material subsidiaries of Emera and any auditor recommendations concerning such subsidiaries.

(f) The Committee may request for review, and shall receive when requested, all related party transactions required to be disclosed pursuant to generally accepted accounting principles, and discuss with Management the business rationale for the transactions and whether appropriate disclosures have been made.

9. Internal Controls

The Committee shall oversee:

(a) the adequacy and effectiveness of the Company' s internal accounting and financial controls and the recommendations of Management, the external auditor and the internal auditors for the improvement of accounting practices and internal controls; and

(b) management' s compliance with the Company' s processes, procedures and internal controls.

In exercising such oversight, the Committee shall review and discuss each of the foregoing with Management, the external auditor and the internal auditor.

The Committee will carry out the following specific duties:

(c) Review and discuss with the Chief Executive Officer and the Chief Financial Officer the procedures undertaken in connection with the Chief Executive Officer and Chief Financial Officer certifications for the annual and interim filings with applicable securities regulatory authorities.

(d) Review disclosures made by Emera' s Chief Executive Officer and Chief Financial Officer during their certification process for the annual and interim filing with applicable securities regulatory authorities about any significant deficiencies in the design or operation of internal controls which could adversely affect Emera' s ability to record, process, summarize and report financial data or any material weaknesses in the internal controls, and any fraud involving management or other employees who have a significant role in the Emera' s internal controls.

(e) Discuss with Emera' s Chief Legal Officer at least annually any legal matters that may have a material impact on the financial statements, operations, assets or compliance policies and any material reports or inquiries received by Emera or any of its subsidiaries from regulators or governmental agencies.

10. Internal Auditor

(a) The lead internal auditor shall report directly to the Committee. The Committee shall approve the appointment, removal and replacement of the lead internal auditor. The Committee shall approve the remuneration of the lead internal auditor on appointment.

(b) The Committee shall review and approve the internal audit plan, including activities, organizational structure, staffing, qualifications and budget, and shall review all major changes to the plan. The Committee shall review and discuss with the internal auditor the scope, progress, and results of executing the internal audit plan. The Committee shall receive reports on the status of significant findings, recommendations, and management' s responses.

(c) The Committee shall meet periodically with the internal auditor to discuss the progress of their activities, any significant findings stemming from internal audits, any issues that arise with Management, and the adequacy of Management' s responses in addressing audit-related deficiencies.

(d) The Committee shall obtain from the internal auditor and review summaries of the significant reports to Management prepared by the internal auditor, and the actual reports if requested by the Committee, and Management' s responses to such reports.

(e) The Committee shall annually receive and review a report on the Chief Executive Officers' expense accounts.

(f) The Committee may communicate with the internal auditor with respect to their reports and recommendations, the extent to which prior recommendations have been implemented and any other matters that the internal auditor brings to the attention of the Committee.

(g) The Committee shall, at least biennially or more frequently as it deems necessary, approve the internal audit charter. The internal auditor shall confirm to the Committee annually that the function adheres to applicable professional standards. The Committee may provide feedback on the performance of the lead internal auditor as deemed necessary.

(h) The Committee shall, biennially or more frequently as it deems necessary, review the independence of the internal audit function and shall make recommendations to the Board on appropriate actions to be taken which the Committee deems necessary to protect and enhance the independence of the internal audit function.

(i) The Committee shall review the results of an external assessment, performed every five years by a qualified independent assessor or assessment team, of the internal audit function in conformance with International Standards for the Professional Practice of Internal Auditing (IPPF Standards).

11. Complaints

The Committee shall oversee procedures relating to the receipt, retention, and treatment of complaints received concerning accounting, internal accounting controls, or auditing matters. The Committee shall also review procedures concerning the confidential, anonymous submission of concerns by Emera' s employees relating to questionable accounting or auditing matters. Without limiting the foregoing, the Committee shall receive periodic ethics updates under Emera' s Code of Conduct which relate to matters within the scope of responsibility of the Committee as defined in this Charter, and the Committee shall review the related activities within that scope under Emera' s Ethics Program, such as financial reporting, accounting and auditing, business integrity, and corporate assets and infrastructure.

12. Other Responsibilities

The Committee shall:

(a) Periodically review Management' s process for identifying non-compliance with legal and regulatory requirements;

(b) Annually receive and review a report on executive officers' compliance with the Company' s Code of Conduct;

(c) Annually provide feedback on the performance of the Chief Financial Officer;

(d) Review actions taken by the Company to identify and manage risks related to the Audit Committee mandate, including Primary Enterprise Risks, which may have the potential to adversely impact the Company' s operations, strategy or reputation; and

(e) Perform such other duties and exercise such powers as may be directed or delegated to the Committee by the Board.

13. Limitation on Authority

Nothing articulated herein is intended to assign to the Committee the Board' s responsibility to oversee Emera' s compliance with applicable laws or regulations or to expand applicable standards of liability under statutory or regulatory requirements for the Directors or the members of the Committee.

PART II
COMPOSITION

14. Composition

(a) Emera' s Articles of Association require that the Committee shall be comprised of no less than three directors none of whom may be officers or employees of Emera nor may they be an officer or employee of any affiliate of Emera. In addition, all members of the Committee shall be independent as required by applicable legislation.

(b) The Board shall appoint members to the Committee who are financially literate, as required by applicable legislation, which at a minimum requires that Committee members have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Emera' s financial statements.

(c) Committee members shall be appointed at the Board meeting following the election of Directors at Emera' s annual shareholders' meeting and membership may be based upon the recommendation of the Nominating and Corporate Governance Committee.

(d) Pursuant to Emera' s Articles of Association, the Board may appoint, remove, or replace any member of the Committee at any time, and a member of the Committee shall cease to be a member of the Committee upon ceasing to be a Director. Subject to the foregoing, each member of the Committee shall hold office as such until the next annual meeting of shareholders after the member' s appointment to the Committee.

(e) The Secretary of the Committee shall advise Emera' s internal and external auditors of the names of the members of the Committee promptly following their election.

PART III
COMMITTEE PROCEDURE

15. Meetings

(a) Meetings of the Committee may be called by the Chair or at the request of any member. The Committee shall meet at least quarterly.

(b) The timing and location of meetings of the Committee, and the calling of and procedure at any such meeting, shall be determined from time to time by the Committee.

(c) Emera' s internal and external auditors shall be notified of all meetings of the Committee and shall have the right to appear before and be heard by the Committee.

(d) Emera' s internal or external auditors may request the Chair of the Committee to consider any matters which the internal or external auditors believe should be brought to the attention of the Committee or the Board.

16. Separate Sessions

(a) The Committee Chair shall meet periodically with the Chief Financial Officer, the lead internal auditor and the external auditor in separate executive sessions to discuss any matters that the Committee or each of these groups believes should be discussed privately.

(b) The Chief Financial Officer, the lead internal auditor and the external auditor shall have access to the Committee to bring forward matters requiring its attention.

(c) The Committee shall meet periodically without Management present.

17. Quorum

A majority of the members of the Committee present in person, by teleconferencing, or by videoconferencing, or by a combination thereof, will constitute a quorum.

18. Chair

Pursuant to Emera' s Articles of Association, the Committee shall choose one of its members to act as Chair of the Committee, which person shall not be the Chair of Nova Scotia Power Inc.' s Audit Committee. In selecting a Committee Chair, the Committee may consider any recommendation made by the Nominating and Corporate Governance Committee.

19. Secretary and Minutes

Pursuant to Emera' s Articles of Association, the Corporate Secretary of Emera shall act as the Secretary of the Committee. Emera' s Articles of Association require that the Minutes of the Committee be in writing and duly entered into Emera' s records, and the Minutes shall be circulated to all members of the Committee. The Secretary shall maintain all Committee records.

20. Board Relationships and Reporting

The Committee shall:

(a) Review annually the Committee' s Charter;

(b) Oversee the appropriate disclosure of the Committee' s Charter as well as other information concerning the Committee which is required to be disclosed by applicable legislation in Emera' s Annual Information Form and any other applicable disclosure documents;

(c) Report to the Board at the next following board meeting on any meeting held by the Committee, and as required, regularly report to the Board on Committee activities, issues, and related recommendations; and

(d) Maintain free and open communication between the Committee, the external auditors, internal auditors, and Management, and determine that all parties are aware of their responsibilities.

21. Powers

The Committee shall:

(a) examine and consider such other matters, and meet with such persons, in connection with the internal or external audit of Emera' s accounts, which the Committee in its discretion determines to be advisable;

(b) have the authority to communicate directly with the internal and external auditors; and

(c) have the right to inspect all records of Emera or its affiliates and may elect to discuss such records, or any matters relating to the financial affairs of Emera with the officers or auditors of Emera and its affiliates.

22. Experts and Advisors

The Committee may, in consultation with the Chairman of the Board, engage and compensate any outside adviser that it determines necessary in order to carry out its duties.

Exhibit 99.2

Management’s Discussion & Analysis

As at February 26, 2024

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its consolidated subsidiaries and investments (collectively referred to as “Emera” or the “Company”) during the fourth quarter of, and for the full year of, 2023 relative to the same periods in 2022 and selected financial information for 2021; and its financial position as at December 31, 2023 relative to December 31, 2022. The Company’s activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

This MD&A should be read in conjunction with the Emera annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2023. Emera follows United States Generally Accepted Accounting Principles (“USGAAP” or “GAAP”). Additional information related to Emera, including the Company’s Annual Information Form can be found on Sedar+ at www.sedarplus.ca.

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, 2023, Emera’s rate-regulated subsidiaries and investments include:

Emera Rate-Regulated Subsidiary or Equity Investment	**Accounting Policies Approved/Examined By**
Subsidiary	
Tampa Electric Company (“TEC”) (1)	Florida Public Service Commission (“FPSC”) and the Federal Energy Regulatory Commission (“FERC”)
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board (“UARB”)
Peoples Gas System, Inc. (“PGS”) (1)	FPSC
New Mexico Gas Company, Inc. (“NMGC”)	New Mexico Public Regulation Commission (“NMPRC”)
SeaCoast Gas Transmission, LLC ("SeaCoast")	FPSC
Emera Brunswick Pipeline Company Limited (“Brunswick Pipeline”)	Canadian Energy Regulator ("CER")
Barbados Light & Power Company Limited (“BLPC”)	Fair Trading Commission, Barbados ("FTC")
Grand Bahama Power Company Limited (“GBPC”)	The Grand Bahama Port Authority (“GBPA”)
Equity Investments	
NSP Maritime Link Inc. (“NSPML”)	UARB
Labrador Island Link Limited Partnership (“LIL”)	Newfoundland and Labrador Board of Commissioners of Public Utilities
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC (“M&NP”)	CER and FERC
St. Lucia Electricity Services Limited (“Lucelec”)	National Utility Regulatory Commission

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

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

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FORWARD-LOOKING INFORMATION

This MD&A contains “forward-looking information” (“FLI”) 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 FLI, although not all FLI contains these identifying words. The FLI 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 FLI 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 FLI. Factors that could cause results or events to differ from current expectations include, without limitation: regulatory and political risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; changes in credit ratings; future dividend growth; timing and costs associated with certain capital investments; expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; country risks; supply chain risk; environmental risks; foreign exchange (“FX”); regulatory and government decisions, including changes to environmental legislation, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology (“IT”) infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on FLI, as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the FLI. All FLI 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 FLI 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 (“US”) and the Caribbean. Cost-of-service utilities provide essential electric and gas services in designated territories under franchises and are overseen by regulatory authorities. Emera’s strategic focus continues to be safely delivering cleaner, affordable and reliable energy to its customers.

The majority of Emera’s investments in rate-regulated businesses are located in Florida with other investments in Nova Scotia, New Mexico and the Caribbean. Emera’s portfolio of regulated utilities provides reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as “rate base”), and the amount of equity in the capital structure and the return on that equity (“ROE”) as approved through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera’s capital investment plan is approximately $9 billion over the 2024 through 2026 period with approximately $2 billion of additional potential capital investments over the same period. The capital investment plan and additional potential capital result in an anticipated compound annual rate base growth in the range of approximately 7 per cent to 8 per cent through 2026. The capital investment plan includes significant investments across the portfolio in renewable and cleaner generation, reliability and system integrity investments, infrastructure modernization, infrastructure expansion to meet the needs of new and existing customers, and technologies to better support the business and customer experiences. It is anticipated that approximately 75 per cent of Emera’s $9 billion capital investment plan over the 2024 through 2026 period will be made in Florida.

Emera’s capital investment plan is being funded primarily through internally generated cash flows, debt raised at the operating company level consistent with regulated capital structures, equity, and select asset sales. Generally, equity requirements in support of the Company’s capital investment plan are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera’s dividend reinvestment plan (“DRIP”) and at-the-market program (“ATM program”). Maintaining investment-grade credit ratings is a priority of the Company.

Emera has provided annual dividend growth guidance of four to five per cent through 2026. The Company targets a long-term dividend payout ratio of adjusted net income of 70 to 75 per cent and, while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time. For further information on the non-GAAP measure “Dividend Payout Ratio of Adjusted Net Income”, refer to the “Non-GAAP Financial Measures and Ratios” section.

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

Energy markets worldwide are experiencing significant change and Emera is well-positioned to continue to respond to shifting customer demands and meet the challenges of digitization, decarbonization and decentralized generation, within complex regulatory environments.

Customers depend on energy and are looking for more choice, better control, and greater reliability. The costs of decentralized generation and storage have become more competitive and advancing technologies are transforming how utilities operate and interact with customers. Concurrently, climate change and the increased frequency of extreme weather events are shaping government energy policy. This is also creating a need to replace aging infrastructure and make investments to protect and harden energy systems to deliver energy reliability and system resiliency. These factors combined with inflation, higher interest rates and higher cost of capital place increased pressure on energy costs, and thus customer rates, at a time when affordability is a challenge.

Emera’s strategy is centered on delivering value for customers, and in doing so creating value for shareholders. This includes:

- investing in cleaner and renewable sources of energy, in the related transmission assets, and in energy storage needed to support intermittent renewables;
- supporting increasing demand from customers and the ongoing electrification of other sectors;
- improving system reliability and resiliency, including replacing aging infrastructure and expanding systems to service new customers; and
- investing in new internal and customer-facing technologies for improved cost efficiency and better customer experiences.

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

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

- A 55 per cent reduction in carbon dioxide emissions by 2025.
- The retirement of Emera’s last existing coal unit no later than 2040.
- An 80 per cent reduction in carbon dioxide emissions by 2040.

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

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

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

NON-GAAP FINANCIAL MEASURES AND RATIOS

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

Adjusted Net Income Attributable to Common Shareholders, Adjusted Earnings (Loss) Per Common Share ("EPS") – Basic and Dividend Payout Ratio of Adjusted Net Income

Emera calculates an adjusted net income attributable to common shareholders ("adjusted net income") measure by excluding the effect of MTM adjustments, the GBPC impairment charge in 2022, and the impact of the 2022 NSPML unrecoverable costs.

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

- held-for-trading ("HFT") commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered, and the related amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the business activities of Bear Swamp Power Company LLC ("Bear Swamp") included in Emera's equity income;
- equity securities held in BLPC and Emera Energy; and
- FX hedges entered into to hedge USD denominated operating unit earnings exposure.

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

In Q4 2022, the Company recognized a $73 million non-cash goodwill impairment charge related to GBPC due to a decline in the fair value ("FV") of the reporting unit driven by the effects of macro-economic factors on the discount rate calculation. Management believes excluding from net income the effect of this charge better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the Company. For further details on the GBPC impairment charge, refer to "Significant Items Impacting Earnings", and "Financial Highlights – Other Electric Utilities" sections.

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

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

Emera calculates adjusted net income for the Canadian Electric Utilities, Other Electric Utilities, and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. Refer to "Financial Highlights – Canadian Electric Utilities", "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections.

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

For the millions of dollars (except per share amounts)	Three months ended December 31 2023	2022	Year ended December 31 2023	2022	2021
Net income attributable to common shareholders	**$ 289**	$ 483	**$ 978**	$ 945	$ 510
MTM gain (loss), after-tax (1)	**114**	307	**169**	175	(213)
GBPC impairment charge	**-**	(73)	**-**	(73)	-
NSPML unrecoverable costs (2)	**-**	-	**-**	(7)	-
Adjusted net income	**$ 175**	$ 249	**$ 809**	$ 850	$ 723
EPS – basic	**$ 1.04**	$ 1.80	**$ 3.57**	$ 3.56	$ 1.98
Adjusted EPS – basic	**$ 0.63**	$ 0.93	**$ 2.96**	$ 3.20	$ 2.81

(1) Net of income tax expense of $44 million for the three months ended December 31, 2023 (2022 – $124 million expense) and $68 million expense for the year ended December 31, 2023 (2022 – $73 million expense) (2021 – $86 million recovery).
(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in “Income from equity investments” on Emera’s Consolidated Statements of Income.

EBITDA and Adjusted EBITDA

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

Similar to adjusted net income calculations described above, adjusted EBITDA represents EBITDA absent the income effect of MTM adjustments, the 2022 GBPC impairment charge and the 2022 NSPML unrecoverable costs.

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

For the millions of dollars	Three months ended December 31 2023	2022	Year ended December 31 2023	2022	2021
Net income (1)	**$ 307**	$ 499	**$ 1,045**	$ 1,009	$ 561
Interest expense, net	**241**	206	**925**	709	611
Income tax expense (recovery)	**51**	154	**128**	185	(6)
Depreciation and amortization	**264**	254	**1,049**	952	902
EBITDA	**$ 863**	$ 1,113	**$ 3,147**	$ 2,855	$ 2,068
MTM gain (loss), before-tax	**158**	431	**237**	248	(299)
GBPC impairment charge	**-**	(73)	**-**	(73)	-
NSPML unrecoverable costs (2)	**-**	-	**-**	(7)	-
Adjusted EBITDA	**$ 705**	$ 755	**$ 2,910**	$ 2,687	$ 2,367

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

2023

Earnings Impact of MTM Gain, After-Tax

MTM gain, after-tax decreased $193 million to $114 million in Q4 2023, compared to $307 million in Q4 2022 primarily due to unfavourable changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 at Emera Energy Services ("EES"). For the year ended December 31, 2023, MTM gain, after-tax decreased $6 million to $169 million compared to $175 million for the same period in 2022 primarily due to higher amortization of gas transportation assets at EES, partially offset by favourable changes in existing positions at EES and gains on Corporate FX hedges.

2022

GBPC Impairment Charge

In Q4 2022, Emera recognized a goodwill impairment charge of $73 million ($0.27 per common share) for GBPC due to a decline in the FV of the reporting unit driven by the effects of macro-economic factors on discount rate calculations. This non-cash charge was recorded in "GBPC Impairment charge" on the Consolidated Statements of Income and reduced the GBPC goodwill balance to nil. For further details, refer to note 22 in the consolidated financial statements.

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

In Q4 2022, a payment of $63 million ($45 million after tax and legal costs, or $0.17 per common share), was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment of TGH, a wholly owned subsidiary of TECO Energy. The payment was recognized in 'Other income, net" on the Consolidated Statements of Income. For further details, refer to note 8 in the consolidated financial statements.

Consolidated Financial Highlights

For the millions of dollars	Three months ended December 31		Year ended December 31		
Adjusted net income	**2023**	2022	**2023**	2022	2021
Florida Electric Utility	**$ 115**	$ 124	**$ 627**	$ 596	$ 462
Canadian Electric Utilities	**68**	46	**247**	222	241
Gas Utilities and Infrastructure	**59**	72	**214**	221	198
Other Electric Utilities	**4**	8	**35**	29	20
Other	**(71)**	(1)	**(314)**	(218)	(198)
Adjusted net income	**$ 175**	$ 249	**$ 809**	$ 850	$ 723
MTM gain (loss), after-tax	**114**	307	**169**	175	(213)
GBPC impairment charge	**-**	(73)	**-**	(73)	-
NSPML unrecoverable costs	**-**	-	**-**	(7)	-
Net income attributable to common shareholders	**$ 289**	$ 483	**$ 978**	$ 945	$ 510

The following table highlights the significant changes in adjusted net income from 2022 to 2023:

For the millions of dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2022	**$ 249**	**$ 850**
Operating Unit Performance		
Increased earnings at NSPI due to new base rates and increased sales volumes, partially offset by higher operating, maintenance and general expenses ("OM&G"), interest expense and depreciation	17	10
Increased income from equity investments at NSPML quarter-over-quarter primarily due to the Maritime Link holdback (the "holdback") recognized in Q4 2022. Year-over-year also due to the partial reversal in Q3 2023 of the holdback recognized in 2022	4	10
Decreased earnings quarter-over-quarter at TEC due to increased interest expense, depreciation, state and municipal taxes, unfavourable weather, and higher OM&G, partially offset by new base rates and customer growth driving higher sales volumes. Increased earnings year-over-year due to new base rates, the impact of a weaker CAD and customer growth, partially offset by higher interest expense, depreciation, state and municipal taxes, and OM&G, and unfavourable weather	(9)	31
Decreased earnings quarter-over-quarter at NMGC primarily due to lower asset optimization revenues and higher OM&G, partially offset by new base rates. Increased earnings year-over-year due to new base rates, partially offset by higher OM&G and interest expense	(11)	12
Decreased earnings at EES due to more favourable market conditions in 2022	(21)	(22)
Corporate		
Decreased OM&G, pre-tax, due to timing of long-term compensation and related hedges	13	10
Increased interest expense, pre-tax, due to higher interest rates and higher debt levels	(9)	(51)
Decreased income tax recovery quarter-over-quarter primarily due to the impact of effective state tax rates	(10)	2
TGH award, after tax and legal costs, in Q4 2022. Refer to the "Significant Items Affecting Earnings" section	(45)	(45)
Other Variances	(3)	2
Adjusted net income – 2023	**$ 175**	**$ 809**

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

For the millions of dollars	**2023**	Year ended December 31 2022	2021
Operating cash flow before changes in working capital	**$ 2,336**	$ 1,147	$ 1,337
Change in working capital	**(95)**	(234)	(152)
Operating cash flow	**$ 2,241**	$ 913	$ 1,185
Investing cash flow	**$ (2,917)**	$ (2,569)	$ (2,332)
Financing cash flow	**$ 939**	$ 1,555	$ 1,311

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

As at millions of dollars	**2023**	December 31 2022	2021
Total assets	**$ 39,480**	$ 39,742	$ 34,244
Total long-term debt (including current portion)	**$ 18,365**	$ 16,318	$ 14,658

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)	Three months ended December 31 2023	2022	Variance	Year ended December 31 2023	2022	Variance	Year ended December 31 2021
Operating revenues	**$ 1,972**	$ 2,358	$ (386)	**$ 7,563**	$ 7,588	$ (25)	$ 5,765
Operating expenses	**1,467**	1,638	171	**5,769**	5,959	190	4,835
Income from operations	**$ 505**	$ 720	$ (215)	**$ 1,794**	$ 1,629	$ 165	$ 930
Other income, net	**$ 51**	$ 102	$ (51)	**$ 158**	$ 145	$ 13	$ 93
Interest expense, net	**$ 241**	$ 206	$ (35)	**$ 925**	$ 709	$ (216)	$ 611
Net income attributable to common shareholders	**$ 289**	$ 483	$ (194)	**$ 978**	$ 945	$ 33	$ 510
Adjusted net income	**$ 175**	$ 249	$ (74)	**$ 809**	$ 850	$ (41)	$ 723
Weighted average shares of common stock outstanding (in millions) (1)	**277.7**	269.0	8.7	**273.6**	265.5	8.1	257.2
EPS – basic	**$ 1.04**	$ 1.80	$ (0.76)	**$ 3.57**	$ 3.56	$ 0.01	$ 1.98
EPS – diluted	**$ 1.04**	$ 1.80	$ (0.76)	**$ 3.57**	$ 3.55	$ 0.02	$ 1.98
Adjusted EPS – basic	**$ 0.63**	$ 0.93	$ (0.30)	**$ 2.96**	$ 3.20	$ (0.24)	$ 2.81
Adjusted EBITDA	**$ 705**	$ 755	$ (50)	**$ 2,910**	$ 2,687	$ 223	$ 2,367
Dividends per common share declared	**$ 0.7175**	$ 0.6900	$ 0.0275	**$ 2.7875**	$ 2.6775	$ 0.1100	$ 2.5750
Dividends per first preferred shares declared:							
Series A				**$ 0.5456**	$ 0.5456	$ -	$ 0.5456
Series B				**$ 1.5583**	$ 0.6869	$ 0.8714	$ 0.4873
Series C				**$ 1.2873**	$ 1.1802	$ 0.1071	$ 1.1802
Series E				**$ 1.1250**	$ 1.1250	$ -	$ 1.1250
Series F				**$ 1.0505**	$ 1.0505	$ -	$ 1.0505
Series H				**$ 1.3140**	$ 1.2250	$ 0.0890	$ 1.2250
Series J				**$ 1.0625**	$ 1.0625	$ -	$ 0.6470
Series L				**$ 1.1500**	$ 1.1500	$ -	$ 0.1638

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

Operating Revenues

For Q4 2023, operating revenues decreased $386 million compared to Q4 2022 and, excluding decreased MTM gains of $286 million, decreased $100 million. The decrease was due to lower fuel revenues at NMGC, TEC, and NSPI; decreased marketing and trading margin at EES; lower asset optimization revenue at NMGC; and unfavourable weather at TEC. These decreases were partially offset by new base rates at TEC, NSPI and NMGC; storm cost recovery surcharge revenue at TEC; customer growth at TEC and NSPI; and favourable weather at NSPI.

For the year ended December 31, 2023, operating revenues decreased $25 million compared to 2022 and, excluding decreased MTM gains of $62 million, increased $37 million. The increase was due to new base rates at TEC, NSPI and NMGC; the impact of a weaker CAD; storm cost recovery surcharge revenue at TEC; and customer growth at TEC and NSPI. These increases were partially offset by lower fuel revenues at NMGC, TEC, NSPI, PGS and BLPC; lower off-system sales at PGS; a change in fuel cost recovery methodology for an industrial customer at NSPI; and decreased marketing and trading margin at EES.

Operating Expenses

For Q4 2023, operating expenses decreased $171 million compared to Q4 2022 and excluding the 2022 GBPC impairment charge of $73 million, decreased $98 million. For the year ended December 31, 2023, operating expenses decreased $190 million compared to 2022 and excluding the 2022 GBPC impairment charge of $73 million, decreased $117 million. The decreases in both periods were due to lower fuel expenses at TEC, NMGC, and PGS; partially offset by higher OM&G at TEC due to storm restoration costs recognized related to the storm cost recovery surcharge revenue, and at NSPI due to higher power generation and transmission and distribution field services cost. Year-over-year the decrease was also due to a change in fuel cost recovery for an industrial customer at NSPI, partially offset by the impact of a weaker CAD and the recognition of the Nova Scotia Renewable Electricity Regulations ("RER") penalty at NSPI.

Other Income, net

For Q4 2023, other income, net decreased $51 million compared to Q4 2022, primarily due to the TGH award in Q4 2022. For the year ended December 31, 2023, other income, net increased $13 million compared to 2022, primarily due to increased FX gains in 2023; higher interest income primarily at TEC; and higher pension non-current service cost recovery, partially offset by the TGH award in 2022.

Interest Expense, net

Interest expense, net for Q4 2023 increased $35 million, and for the year ended December 31, 2023 increased $216 million compared to the same periods in 2022. The increases in both periods were due to higher interest rates; higher borrowings to support capital investments and ongoing operations; and the impact of a weaker CAD.

Net Income and Adjusted Net Income

Net income attributable to common shareholders for Q4 2023, compared to Q4 2022, was unfavourably impacted by the $193 million decrease in MTM gains, after-tax, and favourably impacted by the $73 million GBPC impairment charge from 2022. Excluding these changes, adjusted net income decreased $74 million. This was primarily due to the TGH award in Q4 2022; decreased earnings at EES, NMGC and TEC; lower Corporate income tax recovery; and increased Corporate interest expense. These were partially offset by increased earnings at NSPI and NSPML; and decreased Corporate OM&G due to the timing of long-term compensation and related hedges.

Net income attributable to common shareholders for the year ended 2023, as compared to the same period in 2022, was unfavourably impacted by the $6 million decrease in MTM gains, after-tax, and favourably impacted by the $73 million GBPC impairment charge and the $7 million in NSPML unrecoverable costs from 2022. Excluding these changes, adjusted net income decreased $41 million. The decrease was primarily due to increased Corporate interest expense due to higher interest rates and increased total debt; the TGH award in Q4 2022; and decreased earnings at EES. These were partially offset by increased earnings at TEC, NMGC, NSPI and NSPML.

EPS and Adjusted EPS – Basic

EPS and Adjusted EPS – basic were lower for Q4 2023 due to the increase in weighted average shares of common stock outstanding and decreased earnings as discussed above.

EPS – basic was higher for the year ended December 31, 2023, due to the impact of higher earnings as discussed above. Adjusted EPS – basic was lower for the year ended December 31, 2023 due to the increase in weighted average shares of common stock outstanding and decreased adjusted earnings, as discussed above.

Effect of Foreign Currency Translation

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

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 2023 and 2022 are as follows:

	Three months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Weighted average CAD/USD	**$ 1.36**	$ 1.37	**$ 1.35**	$ 1.34
Period end CAD/USD exchange rate	**$ 1.32**	$ 1.35	**$ 1.32**	$ 1.35

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

For the	Three months ended December 31		Year ended December 31	
millions of USD	**2023**	2022	**2023**	2022
Florida Electric Utility	**$ 85**	$ 91	**$ 466**	$ 458
Gas Utilities and Infrastructure (1)	**41**	45	**142**	143
Other Electric Utilities	**3**	7	**26**	23
Other segment (2)	**(18)**	30	**(95)**	(50)
Total (3)	**$ 111**	$ 173	**$ 539**	$ 574

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.'s USD denominated debt.
(3) Excludes $73 million USD in MTM gain, after-tax, for the three months ended December 31, 2023 (2022 – $222 million USD MTM gain, after-tax) and MTM gain, after-tax of $116 million USD for the year ended December 31, 2023 (2022 – $130 million USD MTM gain, after-tax) and the GBPC impairment charge of nil for the three months and year ended December 31, 2023 (2022 – $54 million USD).

The translation impact of the change in FX rates on foreign denominated earnings increased net income by $13 million in Q4 2023 and $46 million for the year ended December 31, 2023, compared to the same periods in 2022. The translation impact of the change in FX rates on foreign denominated earnings decreased adjusted net income by $3 million in Q4 2023 and increased adjusted net income by $20 million for the year ended December 31, 2023 compared to the same periods in 2022. Impacts of the changes in the translation of the CAD include the impacts of Corporate FX hedges used to mitigate translation risk of USD earnings in the Other segment.

BUSINESS OVERVIEW AND OUTLOOK

Emera's 2023 results were impacted by macroeconomic conditions, specifically higher interest rates as well as other impacts of inflation. These macroeconomic conditions are likely to continue for the near term. For information on general economic risk, including interest rate and inflation risk, refer to the "Enterprise Risk and Risk Management – General Economic Risk" section.

Florida Electric Utility

Florida Electric Utility consists of TEC, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. TEC has $12 billion USD of assets and approximately 840,000 customers at December 31, 2023. TEC owns 6,433 megawatts ("MW") of generating capacity, of which 74 per cent is natural gas fired, 19 per cent is solar and 7 per cent is coal. TEC owns 2,192 kilometres of transmission facilities and 20,299 kilometres of distribution facilities. TEC meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

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

TEC anticipates earning towards the lower end of the ROE range in 2024 but expects earnings to be higher than 2023. Normalizing 2023 for weather, TEC sales volumes in 2024 are projected to be higher than 2023 due to customer growth. TEC expects customer growth rates in 2024 to be comparable to 2023, reflective of the expected economic growth in Florida.

On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 million USD for 2026 and 2027, respectively. TEC's proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024 with a decision expected by the end of 2024.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC's ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the FPSC approved TEC's petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC and issuance of an order by the FPSC is expected by Q3 2024.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings. TEC will determine the timing of the request for recovery of Hurricane Idalia costs at a future time.

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

In 2024, capital investment in the Florida Electric Utility segment is expected to be $1.3 billion USD (2023 – $1.3 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include solar investments, grid modernization, storm hardening investments and building resilience.

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 $7.2 billion of assets and approximately 549,000 customers, NSPI owns 2,422 MW of generating capacity, of which 44 per cent is coal and/or oil-fired; 28 per cent is natural gas and/or oil; 19 per cent is hydro, wind, or solar; 7 per cent is petroleum coke ("petcoke") and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPPs") and community feed-in tariff ("COMFIT") participants, which own 532 MW of capacity. NSPI also has rights to 153 MW of Maritime Link capacity, representing Nalcor Energy's ("Nalcor") Nova Scotia Block ("NS Block") delivery obligations, as discussed below. NSPI owns approximately 5,000 kilometres of transmission facilities and 28,000 kilometres of distribution facilities.

Nalcor is obligated to provide NSPI with approximately 900 Gigawatt hours ("GWh") of energy annually over 35 years. In addition, for the first five years of the NS Block, Nalcor is obligated to provide approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. The Energy Access Agreement enables NSPI to access a market-priced bid from Nalcor for up to 1.8 Terawatt hours ("TWh") of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

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

NSPI expects earnings and sales volumes to be higher in 2024 than 2023 but anticipates earning below its allowed ROE range in 2024.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding Fuel Adjustment Mechanism ("FAM") balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024. A decision is expected in the first half of 2024. It is anticipated that NSPI will apply to the UARB later in 2024 to collect additional under-recovered fuel amounts in 2025 or future periods, subject to the approval of the UARB.

On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023, the $24 million is deferred to "Other long-term assets", pending UARB approval. A decision is expected from the UARB in 2024.

On September 16, 2023, Nova Scotia was struck by post-tropical storm Lee and as a result, approximately 280,000 customers lost power. The total cost of storm restoration was $19 million, with $9 million charged to “OM&G”, $5 million capitalized to property, plant and equipment (“PP&E) and $5 million deferred to the UARB approved storm rider. The storm rider, for each of 2023, 2024, and 2025, allows NSPI to apply to the UARB for deferral and recovery of expenses if major storm restoration expenses exceed approximately $10 million in any given year. The application for deferral of the storm rider is made in the year following the year of the incurred costs, with recovery beginning in the year after the application.

On February 2, 2023, the UARB approved the General Rate Application settlement agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and a further average increase of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB’s established FAM process. It also established a storm rider, described above, and a demand-side management rider. On March 27, 2023, the UARB issued a final order approving the electricity rates effective on February 2, 2023.

In 2024, capital investment, including AFUDC, is expected to be $435 million (2023 – $451 million). NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

Environmental Legislation and Regulations

NSPI is subject to environmental laws and regulations set by both the Government of Canada and the Province of Nova Scotia (the “Province”). NSPI continues to work with both levels of government to comply with these laws and regulations to maximize efficiency of emission control measures and minimize customer cost. NSPI anticipates that costs prudently incurred to achieve legislated compliance will be recoverable under NSPI’s regulatory framework. NSPI faces risks associated with achieving climate-related and environmental legislative requirements, including the risk of non-compliance, which could adversely affect NSPI’s operations and financial performance. For further discussion on these risks and environmental legislation and regulations, refer to the “Enterprise Risk and Risk Management” section. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

Clean Electricity Solutions Task Force:
The Clean Electricity Solutions Task Force (the “Task Force”) was created by the Province in April 2023 to advise the provincial government on Nova Scotia’s transition away from coal to more renewable sources of energy. On February 23, 2024, the Task Force released its report and recommendations, based on engagement with stakeholders, including NSPI. The Task Force report focuses on findings related to system operations, regulatory oversight, reliability, transmission and affordability. The Task Force announced a number of recommendations, including a strengthening of the authority and independence of the regulator and the establishment of an independent system operator, in order to support the continuing transition to clean energy and the achievement of federal and provincial clean energy goals and legislation. The Province announced they intend to accept these recommendations and will table enabling legislation in its upcoming session which starts February 27, 2024.

RER:
On April 6, 2023, the Province levied a $10 million penalty on NSPI for non-compliance with the RER compliance period ending in 2022. The penalty was recorded in “OM&G” on the Consolidated Statements of Income. On May 26, 2023, NSPI initiated an appeal of the penalty through a proceeding with the UARB, as permitted under the RER. On October 12, 2023, the UARB decided that it will hear the appeal by giving due deference to the Province’s decision but permitting the filing of new evidence to support the parties’ positions. The hearing for the matter is scheduled for June 2024 and a decision is expected before the end of 2024.

Carbon Pricing Regulations:
In November 2022, the Province enacted amendments to the Environment Act which provided the framework for Nova Scotia to implement an output-based pricing system ("OBPS") to comply with the Government of Canada's 2023 through 2030 carbon pollution pricing regulations effective January 1, 2023. The Government of Canada approved the Province's proposed system, however the OBPS will be subject to an interim review by the Government of Canada of the standards effective for 2026. The final Output-Based Pricing System Reporting and Compliance Regulations were prescribed by Order in Council dated January 30, 2024. The OBPS implements greenhouse gas ("GHG") emissions performance standards for large industrial GHG emitters that vary by fuel type. GHG emissions in excess of the prescribed intensity standards will be subject to a carbon price that starts at $65 per tonne in 2023 and will increase by $15 per tonne annually, reaching $170 per tonne by 2030. NSPI's regulatory framework provides for the recovery of costs prudently incurred to comply with carbon pricing programs pursuant to NSPI's FAM.

Nova Scotia Cap-and-Trade Program Regulations:
NSPI was a participant in the Nova Scotia Cap-and-Trade Program and was subject to the 2019 through 2022 compliance period. On March 16, 2023, the Province provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 compliance period. As such, compliance costs accrued of $166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of $6 million were not refunded and no further costs were incurred to achieve compliance with the Nova Scotia Cap-and-Trade Program.

Other Legislation

Electricity Act Amendment:
On November 9, 2023, the Province enacted amendments in the Electricity Act which permit the Governor in Council to approve energy storage projects proposed by a public utility and owned wholly or in majority by the public utility if the project is in the best interest of ratepayers. Further, the amendments to the Electricity Act expand the ability of the Province to require NSPI to enter into power purchase agreements with renewable generation facilities by further empowering the Province to require NSPI to enter into an agreement for the sale of the electricity to specified customers. This allows specified customers to buy renewable electricity from specified producers, with NSPI managing the transmission and sale of the energy. On December 21, 2023, the Governor in Council enacted regulations which directed NSPI to install three 50 MW four-hour duration grid-scale batteries as part of the regulated assets of NSPI.

Performance Standards Penalty Amendment:
On April 12, 2023, the Province enacted amendments to the Public Utilities Act which increased the cumulative total of administrative penalties that could be levied by the UARB against NSPI for non-compliance with current and future performance standards in a calendar year from $1 million to $25 million. Any administrative penalties levied against NSPI must be credited to customers and NSPI cannot recover administrative penalties imposed through rates.

ENL

Total equity earnings from NSPML and LIL are expected to be higher in 2024, compared to 2023 resulting from an increased investment in LIL planned for 2024. 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'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.

On December 21, 2023, NSPML received approval to collect up to $164 million from NSPI for the recovery of costs associated with the Maritime Link in 2024; subject to a holdback of $4 million per month, as discussed below.

On October 4, 2023 and January 31, 2024, the UARB issued decisions providing clarification on remaining aspects of the Maritime Link holdback mechanism primarily relating to release of past and future holdback amounts and requirements to end the holdback mechanism. In these decisions, the UARB agreed with the Company's submission that $12 million ($8 million related to 2022 and $4 million relating to 2023) of the previously recorded holdback remain credited to NSPI's FAM, with the remainder released to NSPML and recorded in Emera's "Income from equity investments. NSPML did not record any additional holdback in Q4 2023. The UARB also confirmed that the holdback mechanism will cease once 90 per cent of NS Block deliveries are achieved for 12 consecutive months (subject to potential relief for planned outages or exceptional circumstances) and the net outstanding balance of previously underdelivered NS Block energy is less than 10 per cent of the contracted annual amount. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023. NSPML expects to file an application to terminate the holdback mechanism in 2024.

NSPML does not anticipate any significant capital investment in 2024.

LIL

ENL is a limited partner with Nalcor in LIL. Construction of the LIL is complete and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

Upon issuance of the Commissioning Certificate, AFUDC equity earnings ceased and cash equity earnings and return of equity to Emera commenced. The first distribution was received from the LIL partnership in Q4 2023.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera's current equity investment is $747 million, comprised of $410 million in equity contribution and $337 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million once the final costing has been confirmed by Nalcor to determine the amount of the remaining investment.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure includes PGS, NMGC, SeaCoast, Brunswick Pipeline and Emera's equity 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 $2.8 billion USD of assets and approximately 490,000 customers, the PGS system includes 24,300 kilometres of natural gas mains and 13,500 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2 billion therms in 2023.

Beginning in 2024, the approved ROE range for PGS is 9.15 per cent to 11.15 per cent (2023 – 8.9 per cent to 11.0 per cent), based on an allowed equity capital structure of 54.7 per cent (2023 – 54.7 per cent). An ROE of 10.15 per cent (2023 – 9.9 per cent) is used for the calculation of return on investments for clauses.

New Mexico Gas Company, Inc.

With $1.8 billion USD of assets and approximately 540,000 customers, NMGC's system includes approximately 2,408 kilometres of transmission pipelines and 17,657 kilometres of distribution pipelines. Annual natural gas throughput was approximately 1 billion therms in 2023.

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 2024 than 2023, primarily due to a base rate increase effective January 2024 at PGS and an expected base rate increase effective Q4 2024 at NMGC, partially offset by lower asset optimization revenues expected at NMGC.

PGS expects rate base to be higher than in 2023 and anticipates earning within its allowed ROE range in 2024. USD earnings for 2024 are expected to be to be significantly higher than in 2023 primarily due to higher revenue from new base rates in support of significant ongoing system investment and continued customer growth in 2024, which is expected to be consistent with Florida's population growth rates.

On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

The 2020 PGS rate case settlement provided the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

NMGC expects 2024 rate base growth to be consistent with 2023, with slightly lower USD earnings as a result of lower asset optimization revenues, partially offset by higher revenue from expected new base rates, effective Q4 2024. NMGC anticipates earning near its authorized ROE in 2024. Customer growth rates are expected to be consistent with historical trends.

On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective Q4 2024. NMGC requested a $49 million USD increase in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent. A final order from the NMPRC is expected in Q3 2024.

In 2024, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $465 million USD (2023 – $495 million USD), including AFUDC. PGS and NMGC will make investments to maintain the reliability of their systems and support customer growth.

Other Electric Utilities

Other Electric Utilities includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities. ECI's regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island, and an equity investment in Lucelec on the island of St. Lucia.

BLPC

With $517 million USD of assets and approximately 134,000 customers, BLPC owns 243 MW of generating capacity, of which 96 per cent is oil-fired and four per cent is solar. BLPC owns approximately 188 kilometres of transmission facilities and 3,839 kilometres of distribution facilities. BLPC's approved regulated return on rate base for 2023 was 10 per cent.

GBPC

With $334 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 90 kilometres of transmission facilities and 994 kilometres of distribution facilities. GBPC's approved regulatory return on rate base for 2024 is 8.52 per cent (2023 – 8.32 per cent).

Other Electric Utilities Outlook

Other Electric Utilities' USD earnings in 2024 are expected to increase over the prior year.

BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the “Motion”) and applied for a stay of the FTC’s decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

On December 1, 2023, BLPC appealed certain aspects of the FTC’s February 15 and November 20, 2023, decisions to the Supreme Court of Barbados in the High Court of Justice (the “Court”) and requested that they be stayed. On December 11, 2023, the Court granted the stay. BLPC’s position is that the FTC made errors of law and jurisdiction in their decisions and believes the success of the appeal is probable, and as a result, the adjustments to BLPC’s final rates and rate base, including any adjustments to regulatory assets and liabilities, have not been recorded at this time. Management does not expect the final decision and order to have a material impact on adjusted net income.

In 2024, capital investment in the Other Electric Utilities segment is expected to be approximately $80 million USD (2023 – $47 million USD), primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

Other

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

Business operations in the Other segment include Emera Energy and Block Energy LLC (“Block Energy”). Emera Energy consists of EES, a wholly owned physical energy marketing and trading business and an equity investment in a 50 per cent joint venture ownership of Bear Swamp, a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts. Block Energy is a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers.

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

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

The adjusted net loss from the Other segment is expected to be higher in 2024 due to increased interest expense and lower contribution to net income from Emera Energy primarily as a result of one-time investment tax credits at Bear Swamp in 2023.

The Other segment does not anticipate any significant capital investment in 2024.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2022 and December 31, 2023 include:

millions of dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ 257**	Increased due to cash from operations, proceeds from long-term debt issuances at PGS and NSPI, and issuance of Emera common stock. These were partially offset by investment in PP&E at the regulated utilities, net repayments of debt at TEC, and dividends paid on Emera common stock
Derivative instruments (current and long-term)	**(156)**	Decreased due to settlements of derivative instruments and decreased pricing on power derivative instruments at NSPI, partially offset by reversal of 2022 contracts at EES
Regulatory assets (current and long-term)	**(515)**	Decreased due to higher fuel clause and storm cost recoveries at TEC, and reversal of accrued Cap-and-Trade emission compliance charges at NSPI. These were partially offset by increased FAM deferrals at NSPI due to an under-recovery of fuel costs and a change in fuel cost recovery methodology for an industrial customer, and increased deferred income tax regulatory assets at NSPI
Receivables and other assets (current and long-term)	**(1,079)**	Decreased due to lower gas transportation assets, decreased cash collateral and lower trade receivables as a result of lower commodity prices at EES, and settlement of the gas hedge receivable at NMGC
PP&E, net of accumulated depreciation and amortization	**1,380**	Increased due to capital additions in excess of depreciation and amortization, partially offset by the effect of FX translation of Emera's non-Canadian affiliates
Goodwill	**(141)**	Decreased due to the effect of the FX translation of non-Canadian affiliates
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**$ 754**	Issuance of long-term debt at PGS and NSPI and proceeds from committed credit facilities at Emera, partially offset by net repayments under committed credit facilities at NSPI and TEC, repayment of debt at NMGC, and the effect of the FX translation of non-Canadian affiliates
Accounts payable	**(571)**	Decreased due to lower commodity prices at EES, NMGC and TEC, decreased cash collateral position on derivative instruments and lower fuel related payables at NSPI
Deferred income tax liabilities, net of deferred income tax assets	**185**	Increased due to tax deductions in excess of accounting depreciation related to PP&E, partially offset by changes in derivative instruments and increased tax credits related to solar projects at TEC and Bear Swamp facility upgrades
Derivative instruments (current and long-term)	**(574)**	Decreased due to changes in existing positions and reversal of 2022 contracts, partially offset by new contracts in 2023 at EES
Regulatory liabilities (current and long-term)	**(501)**	Decreased due to lower deferrals related to derivative instruments at NSPI and settlement of NMGC gas hedges
Other liabilities (current and long-term)	**(157)**	Decreased due to reversal of accrued Cap-and-Trade emissions compliance charges at NSPI
Common stock	**700**	Increased due to shares issued
Accumulated other comprehensive income	**(273)**	Decreased due to the effect of the FX translation of non-Canadian affiliates
Retained earnings	**219**	Increased due to net income in excess of dividends paid

OTHER DEVELOPMENTS

Increase in Common Dividend

On September 20, 2023, the Emera Board of Directors (the "Board") approved an increase in the annual common share dividend rate to $2.87 from $2.76 per common share. The first payment was effective November 15, 2023. Emera also extended its dividend growth rate target of four to five per cent through 2026.

FINANCIAL HIGHLIGHTS

Florida Electric Utility

For the millions of USD (except as indicated)		Three months ended December 31 **2023**		2022		Year ended December 31 **2023**		2022
Operating revenues – regulated electric	**$**	**613**	$	597	**$**	**2,637**	$	2,523
Regulated fuel for generation and purchased power	**$**	**162**	$	201	**$**	**682**	$	832
Contribution to consolidated net income	**$**	**85**	$	91	**$**	**466**	$	458
Contribution to consolidated net income – CAD	**$**	**115**	$	124	**$**	**627**	$	596
Average fuel costs in dollars per MWh	**$**	**34**	$	41	**$**	**31**	$	39

The impact of the change in the FX rate increased CAD earnings for the three months and year ended December 31, 2023, by $1 million and $22 million, respectively.

Net Income

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

For the millions of USD		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2022	**$**	**91**	**$**	**458**
Increased operating revenues due to storm cost recovery surcharge revenue (offset in OM&G), new base rates and customer growth driving higher sales volumes, partially offset by changes in fuel recovery clause revenue and unfavourable weather		16		114
Decreased fuel for generation and purchased power due to lower natural gas prices		39		150
Increased OM&G primarily due to storm cost recovery recognition related to the storm surcharge (offset in revenue) and timing of deferred clause recoveries		(25)		(136)
Increased depreciation and amortization due to additions to facilities and generation projects placed in service		(8)		(33)
Increased interest expense due to higher interest rates and higher borrowings to support capital investments and ongoing operations		(7)		(59)
Increased state, and municipal taxes due to higher retail sales and higher taxable property placed in service		(8)		(33)
(Increased) decreased income tax expense primarily due to production tax credits related to solar facilities		(6)		7
Other		(7)		(2)
Contribution to consolidated net income – 2023	**$**	**85**	**$**	**466**

Operating Revenues – Regulated Electric

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

	Electric Revenues (millions of USD)		Electric Sales Volumes (Gigawatt hours ("GWh"))	
	2023	2022	**2023**	2022
Residential	**$ 1,711**	$ 1,381	**10,307**	10,109
Commercial	**803**	666	**6,462**	6,300
Industrial	**203**	176	**2,082**	2,111
Other (1)	**(80)**	300	**2,194**	2,352
Total	**$ 2,637**	$ 2,523	**21,045**	20,872

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

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2023	2022
Natural gas	**17,843**	17,083
Solar	**1,748**	1,492
Purchased power	**1,443**	1,685
Coal	**744**	1,325
Total	**21,778**	21,585

TEC'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 or battery storage), such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance, availability of lower priced short-term purchased power, availability of renewable solar generation, and compliance with environmental standards and regulations.

Regulatory Environment

TEC is regulated by the FPSC and is also subject to regulation by the FERC. The FPSC sets rates at a level that allows utilities such as TEC 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 TEC, the FPSC or other interested parties. For further details on TEC's regulatory environment, base rates and recovery mechanisms, refer to note 6 in the consolidated financial statements.

Canadian Electric Utilities

For the millions of dollars (except as indicated)	Three months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Operating revenues – regulated electric	**$ 439**	$ 421	**$ 1,671**	$ 1,675
Regulated fuel for generation and purchased power (1)	**$ 234**	$ 173	**$ 777**	$ 950
Contribution to consolidated adjusted net income	**$ 68**	$ 46	**$ 247**	$ 222
NSPML unrecoverable costs	**$ -**	$ -	**$ -**	$ (7)
Contribution to consolidated net income	**$ 68**	$ 46	**$ 247**	$ 215
Average fuel costs in dollars per MWh (2)	**$ 81**	$ 61	**$ 70**	$ 85

(1) Regulated fuel for generation and purchased power includes NSPI's FAM deferral on the Consolidated Statements of Income, however, it is excluded in the segment overview.
(2) Average fuel costs for the year ended December 31, 2023 include reversal of the $166 million of the Nova Scotia Cap-and-Trade Program provision (2022 – $134 million expense).

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

For the millions of dollars		Three months ended December 31 **2023**		2022		Year ended December 31 **2023**		2022
NSPI	**$**	**40**	$	23	**$**	**141**	$	131
Equity investment in LIL		**16**		15		**60**		55
Equity investment in NSPML (1)		**12**		8		**46**		36
Contribution to consolidated adjusted net income	**$**	**68**	$	46	**$**	**247**	$	222

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

Net Income

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

For the millions of dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2022	**$**	**46**	**$**	**215**
Increased operating revenues quarter-over-quarter due to new rates, increased residential, commercial and other class sales volumes, and favourable weather, partially offset by decreased industrial sales volume. Year-over-year decrease primarily due to changes in fuel cost recovery methodology for an industrial customer (1), partially offset by quarter-over-quarter impacts noted above		18		(4)
Increased fuel for generation and purchased power quarter-over-quarter due to increased commodity prices and partial reversal of Nova Scotia Cap-and-Trade Program costs accrued in 2022, partially offset by a change in generation mix. Year-over-year decreased due to reversal of the Nova Scotia Cap-and-Trade Program provision in 2023, compared to an expense in 2022, partially offset by increased commodity prices and the Nova Scotia OBPS carbon tax accrual		(61)		173
Increased FAM deferral quarter-over-quarter due to under-recovery of fuel costs. Year-over-year decreased due to reversal of the Nova Scotia Cap-and-Trade provision in 2023, partially offset by increased under-recovery of fuel costs and changes in the fuel recovery methodology for an industrial customer (1)		74		(69)
Increased OM&G due to higher costs for power generation and transmission and distribution field services. Year-over-year also increased due to the recognition of the RER penalty and higher vegetation management costs		(8)		(46)
Increased depreciation and amortization due to increased PP&E in service		(3)		(17)
Increased interest expense due to increased interest rates and higher debt levels		(5)		(34)
Increased income from equity investments at NSPML quarter-over-quarter primarily due to the holdback recognized in Q4 2022. Year-over-year also increased due to partial reversal in Q3 2023 of the holdback recognized in 2022, and higher equity earnings from LIL		5		15
NSPML unrecoverable costs in 2022		-		7
Other		2		7
Contribution to consolidated net income – 2023	**$**	**68**	**$**	**247**

(1) For more information on the changes in fuel cost recovery methodology for an industrial customer, refer to note 6 in the 2023 consolidated financial statements

NSPI

Operating Revenues – Regulated Electric

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

	Electric Revenues (millions of dollars)		Electric Sales Volumes (GWh)	
	2023	2022	**2023**	2022
Residential	**$ 910**	$ 834	**4,986**	4,822
Commercial	**463**	427	**3,053**	3,006
Industrial	**219**	353	**2,164**	2,480
Other	**41**	28	**239**	148
Total	**$ 1,633**	$ 1,642	**10,442**	10,456

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2023	2022
Coal	**3,086**	3,771
Natural gas	**1,946**	1,650
Purchased power	**881**	910
Petcoke	**553**	897
Oil	**145**	251
Total non-renewables	**6,611**	7,479
Purchased power - IPP, COMFIT and imports	**3,251**	2,423
Wind, hydro and solar	**1,149**	1,105
Biomass	**128**	127
Total renewables	**4,528**	3,655
Total production volumes	**11,139**	11,134

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

Generation mix may also be affected by plant outages, carbon pricing programs, including the Nova Scotia OBPS, availability of renewable generation, availability of energy from the NS Block, plant performance, and compliance with environmental regulations.

The Nova Scotia Cap-and-Trade Program provision related to the accrued cost of acquiring emissions credits for the 2019 through 2022 compliance period. As of December 31, 2022, NSPI had recognized a cumulative $166 million accrual in fuel costs related to anticipated purchase of emissions credits and $6 million related to credits purchased from provincial auction. Accrued compliance costs of $166 million were reversed in Q1 2023 and NSPI does not anticipate further costs related to the Nova Scotia Cap-and-Trade Program. For further information on the reversal of this non-cash accrual and the FAM regulatory balance, refer to the "Business Overview and Outlook – Canadian Electric Utilities – NSPI" section and note 6 in the consolidated financial statements.

Regulatory Environment - NSPI

NSPI is a public utility as defined in the Public Utilities Act and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request. For further details on NSPI's regulatory environment and recovery mechanisms, refer to note 6 in the consolidated financial statements.

Gas Utilities and Infrastructure

For the millions of USD (except as indicated)	Three months ended December 31 **2023**	 2022	Year ended December 31 **2023**	 2022
Operating revenues – regulated gas (1)	**$ 290**	$ 372	**$ 1,114**	$ 1,296
Operating revenues – non-regulated	**3**	2	**15**	12
Total operating revenue	**$ 293**	$ 374	**$ 1,129**	$ 1,308
Regulated cost of natural gas	**$ 99**	$ 181	**$ 391**	$ 614
Contribution to consolidated net income	**$ 43**	$ 53	**$ 158**	$ 170
Contribution to consolidated net income – CAD	**$ 59**	$ 72	**$ 214**	$ 221

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2022 – $13 million) for the three months ended December 31, 2023 and $46 million (2022 – $47 million) for the year ended December 31 2023; however, it is excluded from the gas revenues and cost of natural gas analysis below.

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

For the millions of USD	Three months ended December 31 **2023**	 2022	Year ended December 31 **2023**	 2022
PGS	**$ 21**	$ 17	**$ 79**	$ 82
NMGC	**14**	22	**43**	35
Other	**8**	14	**36**	53
Contribution to consolidated net income	**$ 43**	$ 53	**$ 158**	$ 170

Impact of the change in the FX rate on CAD earnings was minimal for the three months ended and increased CAD earnings for the year ended December 31, 2023, by $8 million.

Net Income

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

For the millions of USD	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2022	**$ 53**	**$ 170**
Decreased operating revenues due to lower fuel revenues at PGS and NMGC, and lower off-system sales at PGS, partially offset by new base rates at NMGC and customer growth at PGS	(71)	(181)
Decreased asset optimization revenue quarter-over-quarter at NMGC	(10)	2
Decreased cost of natural gas sold due to lower natural gas prices at PGS and NMGC	82	223
Increased OM&G primarily due to higher labour and benefit costs	(10)	(20)
Decreased depreciation and amortization expense quarter-over-quarter due to a higher reversal of accumulated depreciation in 2023 as a result of the 2021 rate case settlement at PGS. Year-over-year increase due to asset growth at PGS and NMGC, partially offset by a higher reversal of accumulated depreciation in 2023 at PGS	6	(3)
Increased interest expense due to higher interest rates and increased borrowings to support ongoing operations and capital investments	(10)	(33)
Other	3	-
Contribution to consolidated net income – 2023	**$ 43**	**$ 158**

Operating Revenues – Regulated Gas

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

	Gas Revenues (millions of USD)		Gas Volumes (Therms)	
	2023	2022	**2023**	**2022**
Residential	**$ 537**	$ 614	**414**	421
Commercial	**315**	354	**839**	836
Industrial (1)	**69**	64	**1,615**	1,429
Other (2)	**147**	217	**266**	227
Total (3)	**$ 1,068**	$ 1,249	**3,134**	2,913

(1) Industrial gas revenue includes sales to power generation customers.
(2) Other gas revenue includes off-system sales to other utilities and various other items.
(3) Total gas revenue excludes $46 million of finance income from Brunswick Pipeline (2022 – $47 million).

Regulated Cost of Natural Gas

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

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

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

Gas Volumes by Type (millions of Therms)	2023	2022
Transportation	**2,461**	2,206
System supply	**673**	707
Total	**3,134**	2,913

Regulatory Environments

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

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

For further information on PGS and NMGC's regulatory environment and recovery mechanisms, refer to note 6 in the consolidated financial statements.

Other Electric Utilities.

For the millions of USD (except as indicated)	Three months ended December 31 2023	 2022	Year ended December 31 2023	 2022
Operating revenues – regulated electric	**$ 104**	$ 98	**$ 390**	$ 398
Regulated fuel for generation and purchased power	**$ 57**	$ 54	**$ 204**	$ 223
Contribution to consolidated adjusted net income	**$ 3**	$ 7	**$ 26**	$ 23
Contribution to consolidated adjusted net income – CAD	**$ 4**	$ 8	**$ 35**	$ 29
GBPC Impairment charge	**$ -**	$ 54	**$ -**	$ 54
Equity securities MTM gain (loss)	**$ 2**	$ 1	**$ 2**	$ (4)
Contribution to consolidated net income (loss)	**$ 5**	$ (46)	**$ 28**	$ (35)
Contribution to consolidated net income (loss) – CAD	**$ 6**	$ (62)	**$ 37**	$ (48)
Electric sales volumes (GWh)	**323**	301	**1,260**	1,239
Electric production volumes (GWh)	**345**	325	**1,362**	1,340
Average fuel cost in dollars per MWh	**$ 165**	$ 161	**$ 150**	$ 166

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

The impact of the change in the FX rate on CAD earnings for the three months and year ended December 31, 2023 was minimal.

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

For the millions of USD	Three months ended December 31 2023	 2022	Year ended December 31 2023	 2022
BLPC	**$ 4**	$ 5	**$ 18**	$ 11
GBPC	**-**	1	**11**	10
Other	**(1)**	1	**(3)**	2
Contribution to consolidated adjusted net income	**$ 3**	$ 7	**$ 26**	$ 23

Net Income

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

For the millions of USD	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2022	**$ (46)**	**$ (35)**
Increased operating revenues quarter-over-quarter due to higher fuel revenue at BLPC and GBPC as a result of higher fuel prices and higher sales volumes at BLPC. Year-over-year decreased due to lower fuel revenue at BLPC reflecting lower fuel prices, and the sale of Domlec in Q1 2022, partially offset by interim rates at BLPC and increased sales volumes at BLPC and GBPC	6	(8)
Increased fuel for generation and purchased power quarter-over-quarter due to higher fuel costs at BLPC and GBPC. Decreased year-over-year due to lower fuel prices and change in generation mix at BLPC	(3)	19
GBPC impairment charge in 2022	54	54
Other	(6)	(2)
Contribution to consolidated net income – 2023	**$ 5**	**$ 28**

Regulatory Environments

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

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

For further details on BLPC and GBPC's regulatory environments and recovery mechanisms, refer to note 6 in the consolidated financial statements.

Other

For the millions of dollars	Three months ended December 31 **2023**	 2022	Year ended December 31 **2023**	 2022
Marketing and trading margin (1) (2)	**$ 35**	$ 72	**$ 96**	$ 143
Other non-regulated operating revenue	**5**	3	**27**	16
Total operating revenues – non-regulated	**$ 40**	$ 75	**$ 123**	$ 159
Contribution to consolidated adjusted net income (loss)	**$ (71)**	$ (1)	**$ (314)**	$ (218)
MTM gain, after-tax (3)	**112**	304	**167**	179
Contribution to consolidated net income (loss)	**$ 41**	$ 303	**$ (147)**	$ (39)

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

(2) Marketing and trading margin excludes a MTM gain, pre-tax of $131 million in Q4 2023 (2022 – $430 million gain) and a gain of $216 million for the year ended December 31, 2023 (2022 – $281 million gain).

(3) Net of income tax expense of $44 million for the three months ended December 31, 2023 (2022 – $124 million expense) and $68 million expense for the year ended December 31, 2023 (2022 – $73 million expense).

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

For the millions of dollars	Three months ended December 31 2023	2022	Year ended December 31 2023	2022
Emera Energy:				
EES	**$ 19**	$ 40	**$ 46**	$ 68
Other	**6**	1	**18**	2
Corporate – see breakdown of adjusted contribution below	**(91)**	(37)	**(356)**	(267)
Block Energy LLC (1)	**(4)**	(5)	**(18)**	(18)
Other	**(1)**	-	**(4)**	(3)
Contribution to consolidated adjusted net income (loss)	**$ (71)**	$ (1)	**$ (314)**	$ (218)

(1) Previously Emera Technologies LLC

Net Income

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

For the millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income (loss) – 2022	**$ 303**	**$ (39)**
Decreased marketing and trading margin quarter-over-quarter primarily due to weather driven market conditions in Q4 2022 that increased pricing and volatility. Year-over-year decrease reflects less favourable market conditions, specifically lower natural gas prices and volatility and higher cost commitments for gas transportation in 2023 compared to 2022	(37)	(47)
Decreased OM&G, pre-tax, primarily due to the timing of long-term compensation and related hedges	12	10
Increased interest expense, pre-tax, due to increased interest rates and increased total debt	(8)	(51)
Increased income tax recovery primarily due to increased losses before provision for income taxes and the recognition of investment tax credits related to Bear Swamp facility upgrades, partially offset by the impact of effective state tax rates	7	26
TGH award in 2022, after tax and legal costs	(45)	(45)
Decreased MTM gain, after-tax, quarter-over-quarter due to unfavourable changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 at EES. Decreased MTM gain after-tax, year-over-year primarily due to higher amortization of gas transportation assets partially offset by favourable changes in existing positions at EES and gains on Corporate FX hedges	(194)	(12)
Other	3	11
Contribution to consolidated net income (loss) – 2023	**$ 41**	**$ (147)**

Emera Energy

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

EES' contribution to consolidated adjusted net income was $19 million in Q4 2023, compared to $40 million in Q4 2022; and $46 million ($33 million USD) for the year ended December 31, 2023, compared to $68 million ($50 million USD) for the same period in 2022. The 2023 and 2022 EES contribution to consolidated adjusted net income was above the expected EES annual adjusted net income guidance range of $15 to $30 million USD. Market conditions in 2022 were very favourable, due to high natural gas pricing and volatility, which reflected weather patterns and geopolitical conditions.

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 table below.

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

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

Emera Corporate has FX forwards to manage the cash flow risk of forecasted USD cash inflows. Fluctuations in the FX rate result in MTM gains or losses are recorded in "Other income, net" on the Consolidated Statements of Income.

Corporate

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

For the millions of dollars	Three months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Operating expenses (1)	**$ 7**	$ 20	**$ 73**	$ 83
Interest expense	**88**	79	**329**	278
Income tax recovery	**(25)**	(35)	**(111)**	(109)
Preferred dividends	**18**	16	**66**	63
TGH award, after tax and legal costs	**-**	(45)	**-**	(45)
Other (2)(3)	**3**	2	**(1)**	(3)
Corporate adjusted net loss (4)	**$ (91)**	$ (37)	**$ (356)**	$ (267)

(1) Operating expenses include OM&G and depreciation.

(2) Other includes realized FX gains and losses on FX hedges entered into to hedge USD denominated operating unit earnings exposure.

(3) Includes a realized net loss, pre-tax of $4 million ($3 million after-tax) for the three months ended December 31, 2023 (2022 – $5 million net loss, pre-tax and $4 million loss, after-tax) and a $11 million net loss, pre-tax ($8 million after-tax) for the year ended December 31, 2023 (2022 – $6 million net loss, pre-tax and $5 million loss after-tax) on FX hedges, as discussed above.

(4) Excludes a MTM gain, after-tax of $15 million for the three months ended December 31, 2023 (2022 – $9 million gain, after-tax) and a MTM gain, after-tax of $20 million for the year ended December 31, 2023 (2022 – $12 million loss, after-tax).

LIQUIDITY AND CAPITAL RESOURCES

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

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has an approximate $9 billion capital investment plan over the 2024 through 2026 period with approximately $2 billion of additional potential capital investments over the same period. Capital investments at Emera's regulated utilities are subject to regulatory approval.

Emera plans to use cash from operations, debt raised at the utilities, equity, and select asset sales 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. Generally, equity requirements in support of the Company's capital investment plan are expected to be funded through issuance of preferred equity and issuance of common equity through Emera's DRIP and ATM programs.

Emera has credit facilities with varying maturities that cumulatively provide $5.3 billion of credit, with approximately $2.3 billion undrawn and available at December 31, 2023. The Company was holding a cash balance of $588 million at December 31, 2023. For further discussion, refer to the "Debt Management" section below. For additional information regarding the credit facilities, refer to notes 23 and 25 in the consolidated financial statements.

Consolidated Cash Flow Highlights

Significant changes in the Consolidated Statements of Cash Flows between the years ended December 31, 2023 and 2022 include:

millions of dollars	2023	2022	$ Change
Cash, cash equivalents and restricted cash, beginning of period	$ 332	$ 417	$ (85)
Provided by (used in):			
Operating cash flow before changes in working capital	2,336	1,147	1,189
Change in working capital	(95)	(234)	139
Operating activities	$ 2,241	$ 913	$ 1,328
Investing activities	(2,917)	(2,569)	(348)
Financing activities	939	1,555	(616)
Effect of exchange rate changes on cash, cash equivalents and restricted cash	(7)	16	(23)
Cash, cash equivalents, and restricted cash, end of period	$ 588	$ 332	$ 256

Cash Flow from Operating Activities

Net cash provided by operating activities increased $1,328 million to $2,241 million for the year ended December 31, 2023, compared to $913 million in 2022.

Cash from operations before changes in working capital increased $1,189 million for the year ended December 31, 2023. This increase was due to higher fuel clause recoveries and favourable changes in the storm reserve balance at TEC, decreased fuel for generation and purchased power expense at NSPI driven by the decreased Nova Scotia Cap-and-Trade Program provision and a distribution received from the LIL partnership. This was partially offset by a decrease in regulatory liabilities due to 2022 gas hedge settlements at NMGC, and receipt of the TGH award in 2022.

Changes in working capital increased operating cash flows by $139 million for the year ended December 31, 2023. This increase was due to favourable changes in accounts receivable at NMGC due to receipt of its 2022 gas hedge settlement, favourable changes in cash collateral positions at Emera Energy, favourable changes in natural gas inventory at EES in 2023, and the required prepayment of income taxes and related interest in 2022 at NSPI. These increases were offset by the timing of accounts payable payments at NSPI, TEC and NMGC, unfavourable changes in cash collateral positions at NSPI, and decreased accrual for the Nova Scotia Cap-and-Trade emissions compliance charges at NSPI.

Cash Flow used in Investing Activities

Net cash used in investing activities increased $348 million to $2,917 million for the year ended December 31, 2023, compared to $2,569 million in 2022. The increase was due to higher capital investment in 2023.

Capital expenditures for the year ended December 31, 2023, including AFUDC, were $2,976 million compared to $2,646 million in 2022. Details of 2023 capital spending by segment are shown below:

- $1,771 million – Florida Electric Utility (2022 – $1,481 million);
- $461 million – Canadian Electric Utilities (2022 – $518 million);
- $673 million – Gas Utilities and Infrastructure (2022 – $578 million);
- $63 million – Other Electric Utilities (2022 – $63 million); and
- $8 million – Other (2022 – $6 million).

Cash Flow from Financing Activities

Net cash provided by financing activities decreased $616 million to $939 million for the year ended December 31, 2023, compared to $1,555 million in 2022. This decrease was due to lower proceeds from long-term debt at TEC, higher repayment of short-term debt at TEC, lower proceeds from short-term debt at TECO Finance and Emera, and higher repayments of committed credit facilities at NSPI. This was partially offset by proceeds from long-term debt at PGS and NSPI, retirement of long-term debt at TEC in 2022, and higher issuance of common stock.

Working Capital

As at December 31, 2023, Emera's cash and cash equivalents were $567 million (2022 – $310 million) and Emera's investment in non-cash working capital was $831 million (2022 – $1,173 million). Of the cash and cash equivalents held at December 31, 2023, $482 million was held by Emera's foreign subsidiaries (2022 – $250 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, 2023, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2024	2025	2026	2027	2028	Thereafter	Total
Long-term debt principal	$ 1,670	$ 264	$ 3,047	$ 666	$ 525	$ 12,318	$ 18,490
Interest payment obligations (1)	836	807	719	626	587	7,438	11,013
Transportation (2)	696	495	405	388	338	2,597	4,919
Purchased power (3)	274	249	263	312	312	3,435	4,845
Fuel, gas supply and storage	556	215	62	-	5	-	838
Capital projects	778	111	70	1	-	-	960
Asset retirement obligations	10	2	1	1	2	407	423
Pension and post-retirement obligations (4)	28	29	38	47	32	155	329
Equity investment commitments (5)	240	-	-	-	-	-	240
Other	154	147	56	46	35	221	659
	$ 5,242	$ 2,319	$ 4,661	$ 2,087	$ 1,836	$ 26,571	$ 42,716

(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, 2023, 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 $134 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(3) Annual requirement to purchase electricity production from IPPs or other utilities over varying contract lengths.
(4) The estimated contractual obligation is calculated as the current legislatively required contributions to the registered funded pension plans (excluding the possibility of wind-up), plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.
(5) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion. In December 2023, the UARB approved collection of up to $164 million from NSPI for recovery of Maritime Link costs in 2024. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Construction of the LIL is complete and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

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 and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Other" in the above table.

Forecasted Consolidated Capital Investments

The 2024 forecasted consolidated capital investments are as follows:

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Total
Generation	$ 266	$ 143	$ -	$ 30	$ -	$ 439
New renewable generation	280	-	-	-	-	280
Electric transmission	119	88	-	-	-	207
Electric distribution	496	142	-	58	-	696
Gas transmission and distribution	-	-	566	-	-	566
Facilities, equipment, vehicles, and other	567	63	51	17	4	702
	$ 1,728	$ 436	$ 617	$ 105	$ 4	$ 2,890

Debt Management

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

millions of Canadian dollars (unless otherwise indicated)	**Maturity**	**Credit Facilities**	**Utilized**	**Undrawn and Available**
Emera – Unsecured committed revolving credit facility	June 2027	$ 900	$ 265	$ 635
TEC (in USD) – Unsecured committed revolving credit facility	December 2026	800	707	93
NSPI – Unsecured committed revolving credit facility	December 2027	800	332	468
Emera – Unsecured non-revolving facility	December 2024	400	400	-
Emera – Unsecured non-revolving facility	February 2024	400	200	200
Emera – Unsecured non-revolving facility	August 2024	400	400	-
TECO Finance (in USD) – Unsecured committed revolving credit facility	December 2026	400	185	215
NSPI – Unsecured non-revolving facility	July 2024	400	400	-
PGS (in USD) – Unsecured revolving facility	December 2028	250	55	195
TEC (in USD) - Unsecured revolving facility	February 2024	200	-	200
TEC (in USD) - Unsecured revolving facility	April 2024	200	-	200
NMGC (in USD) – Unsecured revolving credit facility	December 2026	125	21	104
NMGC (in USD) – Unsecured non-revolving facility	March 2024	23	23	-
Other (in USD) – Unsecured committed revolving credit facilities	Various	21	6	15

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, 2023. Emera's significant covenant is listed below:

	Financial Covenant	Requirement	As at December 31, 2023
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.57 : 1

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

Florida Electric Utilities

On January 30, 2024, TEC issued $500 million USD of senior unsecured bonds that bear interest at 4.90 per cent with a maturity date of March 1, 2029. Proceeds from the issuance were primarily used for the repayment of short-term borrowings outstanding under the 5-year credit facility. Therefore, $497 million USD of short-term borrowings that was repaid was classified as long-term debt at December 31, 2023.

On November 24, 2023, TEC repaid its $400 million USD unsecured non-revolving facility, which expired on December 13, 2023.

On April 3, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on April 1, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term secured overnight financing rate ("SOFR"), Wells Fargo's prime rate, the federal funds rate or the one-month SOFR, plus a margin. Proceeds from this facility will be used for general corporate purposes.

On March 1, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on February 28, 2024. The credit facility contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term SOFR, the Bank of Nova Scotia's prime rate, the federal funds rate or the one-month SOFR, plus a margin. Proceeds from this facility will be used for general corporate purposes.

Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053. Proceeds from these issuances were added to the general funds of the Company and applied primarily to refinance existing indebtedness, to finance capital investment and for general corporate purposes.

Gas Utilities and Infrastructure

On December 19, 2023, PGS completed an issuance of $925 million USD in senior notes. The issuance included $350 million USD senior notes that bear interest at 5.42 per cent with a maturity date of December 19, 2028, $350 million USD senior notes that bear interest at 5.63 per cent with a maturity date of December 19, 2033 and $225 million USD senior notes that bear interest at 5.94 per cent with a maturity date of December 19, 2053. Proceeds from these issuances were used to settle intercompany loan agreements with TEC for the assets and liabilities transferred to PGS as part of the reorganization of the gas division of Tampa Electric, effective on January 1, 2023.

On December 1, 2023, PGS entered into a $250 million USD senior unsecured revolving credit facility with a group of banks, maturing on December 1, 2028. PGS has the ability to request the lenders to increase their commitments under the credit facility by up to $100 million USD in the aggregate subject to agreement from participating lenders. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from these facilities will be used for general corporate purposes.

On October 19, 2023, NMGC issued $100 million USD in senior unsecured notes that bear interest at 6.36 per cent with a maturity date of October 19, 2033. Proceeds from the issuance were used to repay short-term borrowings.

Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028. Proceeds from this issuance were used to repay GBPC's $28 million USD bond, which matured in May 2023.

Other

On December 16, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from December 16, 2023 to December 16, 2024. There were no other changes in commercial terms from the prior agreement.

On August 18, 2023, Emera entered into a $400 million non-revolving term facility which matures on February 19, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from this facility will be used for general corporate purposes. On February 16, 2024, Emera extended the term of this agreement to a maturity date of February 19, 2025.

On June 30, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from August 2, 2023 to August 2, 2024. There were no other changes in commercial terms from the prior agreement.

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030. The proceeds were used to repay Emera's $500 million unsecured fixed rate notes, which matured in June 2023.

Credit Ratings

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

	Fitch	S&P	Moody's	DBRS
Emera Inc.	BBB (Negative)	BBB- (Negative)	Baa3 (Negative)	N/A
TEC	A (Negative)	BBB+ (Negative)	A3 (Negative)	N/A
PGS (1)	A (Negative)	N/A	N/A	N/A
NMGC	BBB+ (Negative)	N/A	N/A	N/A
NSPI	N/A	BBB- (Negative)	N/A	BBB (high)(stable)

(1) On November 10, 2023 Fitch Ratings ("Fitch") assigned first-time long-term issuer default rating of 'A-' to PGS and an instrument rating of 'A' for its private placements of senior unsecured bonds.

Guaranteed Debt

As of December 31, 2023, the Company had $2.75 billion USD (2022 – $2.75 billion USD) senior unsecured notes ("US Notes") outstanding.

The US 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 US Notes (such subsidiaries are referred to as the "Non-Guarantor Subsidiaries"); however, Emera has unrestricted access to the assets of consolidated entities.

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

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

Summarized Statement of Income (Loss)

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

For the	Year ended December 31	
millions of dollars	**2023**	**2022**
Loss from operations	**$ (62)**	$ (73)
Net gains (losses) (1)	**$ 349**	$ (131)

(1) Includes $750 million (2022 – $262 million) in interest and dividend income, net, from non-guarantor subsidiaries.

Summarized Balance Sheet

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

As at	December 31	
millions of dollars	**2023**	**2022**
Current assets (1)	**$ 223**	$ 172
Goodwill	**5,871**	6,012
Other assets (2)	**6,243**	6,402
Total assets (3)	**$ 12,337**	$ 12,586
Current liabilities (4)	**$ 1,451**	$ 1,903
Long-term liabilities (5)	**6,815**	6,431
Total liabilities	**$ 8,266**	$ 8,334

(1) Includes $179 million (2022 – $144 million) in amounts due from non-guarantor subsidiaries.
(2) Includes $5,941 million (2022 – $6,058 million) in amounts due from non-guarantor subsidiaries.
(3) Excludes investments in non-guarantor subsidiaries. Consolidated Emera total assets are $39,480 million (2022 – $39,742 million).
(4) Includes $411 million (2022 – $392 million) due to non-guarantor subsidiaries.
(5) Includes $619 million (2022 – $769 million) due to non-guarantor subsidiaries.

Outstanding Stock Data

Common Stock

Issued and outstanding:	millions of shares		millions of dollars
Balance, December 31, 2022	269.95	$	7,762
Issuance of common stock under ATM program (1)	8.29		397
Issued under the DRIP, net of discounts	5.26		272
Senior management stock options exercised and Employee Share Purchase Plan	0.62		31
Balance, December 31, 2023	**284.12**	**$**	**8,462**

(1) For the year ended December 31,2023, 8,287,037 common shares were issued under Emera's ATM program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs). As at December 31,2023, an aggregate gross sales limit of $200 million remained available for issuance under the ATM program.

As at February 20, 2024, the amount of issued and outstanding common shares was 285.8 million.

If all outstanding stock options were converted as at February 20, 2024, an additional 3.1 million common shares would be issued and outstanding.

ATM Equity Program

On October 3, 2023, Emera filed a short form base shelf prospectus, primarily in support of the renewal of its ATM Program in Q4 2023 that will allow 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. This ATM Program is expected to remain in effect until November 4, 2025.

Preferred Stock

As at February 20, 2024, Emera had the following preferred shares issued and outstanding: Series A – 4.9 million; Series B – 1.1 million; Series C – 10.0 million; Series E – 5.0 million; Series F – 8.0 million; Series H – 12.0 million; Series J – 8.0 million, and Series L – 9.0 million. Emera’s preferred shares do not have voting rights unless the Company fails to pay, in aggregate, eight quarterly dividends.

On July 6, 2023, Emera announced it would not redeem the 10 million outstanding Cumulative Rate Reset Preferred Shares, Series C (“Series C Shares”) or the 12 million outstanding Cumulative Minimum Rate Reset First Preferred Shares, Series H (“Series H Shares”) on August 15, 2023.

On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C Shares were converted into Cumulative Floating Rate First Preferred Shares, Series D Shares and no Series H shares were converted into Cumulative Floating Rate First Preferred Shares, Series I shares. The holders of the Series C Shares are entitled to receive a dividend of 6.434 per cent per annum on the Series C Shares during the five-year period commencing on August 15, 2023, and ending on (and inclusive of) August 14, 2028 ($0.40213 per Series C Share per quarter). The holders of the Series H Shares are entitled to receive a dividend of 6.324 per cent per annum on the Series H Shares during the five-year period commencing on August 15, 2023, and ending on (and inclusive of) August 14, 2028 ($0.39525 per Series H Share per quarter).

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit (“DB”) 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. Expected cash flow for DB pension plans is $34 million in 2024 (2023 – $42 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

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

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per each pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of domestic and global equities, domestic and global bonds and short-term investments. The Company 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 2024 (2023 – $45 million).

Defined Benefit Pension Plan Summary

in millions of dollars

Plans by region	TECO Energy	NSPI	Caribbean	Total
Assets as at December 31, 2023	$ 907	$ 1,381	$ 10	$ 2,298
Accounting obligation at December 31, 2023	$ 896	$ 1,361	$ 16	$ 2,273
Accounting expense (income) during fiscal 2023	$ 4	$ (16)	$ 1	$ (11)

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, 2023 totalled $200 million (2022 – $200 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 66 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.

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, 2023:

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

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

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

NSPI has issued guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of $104 million USD (2022 – $119 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $103 million USD (December 31, 2022 – $145 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 2024. The amount committed as at December 31, 2023 was $56 million (December 31, 2022 – $63 million).

DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of four to five per cent through 2026. The Company targets a long-term dividend payout ratio of adjusted net income of 70 to 75 per cent and, while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time. Emera's common share dividends paid in 2023 were $2.7875 ($0.6900 in Q1, Q2, and Q3 and $0.7175 in Q4) per common share and $2.6775 ($0.6625 in Q1, Q2, and Q3 and $0.6900 in Q4) per common share for 2022, representing a dividend payout ratio of 78 per cent in 2023 (2022 – 75 per cent) and a dividend payout ratio of adjusted net income of 94 per cent in 2023 (2022 – 83 per cent).

On September 20, 2023, the Board approved an increase in the annual common share dividend rate to $2.87 from $2.76 per common share. The first quarterly dividend payment at the increased rate was paid on November 15, 2023.

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 $163 million for the year ended December 31, 2023 (2022 – $157 million). NSPML is accounted for as an equity investment, and therefore 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 $14 million for the year ended December 31, 2023 (2022 – $9 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, 2023 and at December 31, 2022.

ENTERPRISE RISK AND RISK MANAGEMENT

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

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

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

Regulatory and Political Risk

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

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

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

Emera's utilities generally manage this risk through transparent regulatory disclosure, ongoing stakeholder and government consultation, and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries work to establish collaborative relationships with regulatory stakeholders, including customer representatives, both through its approach to filings and additional efforts with technical conferences and, where appropriate, negotiated settlements.

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

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

Global Climate Change Risk

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

Climate change may lead to increased frequency and intensity of events and related impacts such as hurricanes, ice and other storms, heavy rainfall, cyclones, extreme winds, wildfires, flooding and droughts. 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's long-term capital investment plan includes significant investment across the portfolio in renewable and cleaner generation, infrastructure modernization, storm hardening, energy storage and customer-focused technologies. All these initiatives contribute toward mitigating the potential impacts of climate change. The Company continues to engage with government, regulators, industry partners and stakeholders to share information and participate in the development of climate change related policies and initiatives.

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

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

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

Supply Chain:
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. Refer to "Supply Chain Risk" and "Uninsured Risk".

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

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

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

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

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

The Company operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities. The Company is reinvesting in the efficiency of certain hydroelectric generation facilities to increase generation capacity and continues to monitor changing hydrology patterns. Such issues may also affect the availability of purchased power from third-party owned hydroelectricity 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, TEC could see lower demand in summer months if temperatures are cooler than expected. Further, extreme weather conditions such as hurricanes and other severe weather conditions which may be associated with climate change could cause these seasonal fluctuations to be more pronounced. In the absence of a regulatory recovery mechanism for unanticipated costs, such events could influence the Company's results of operations, financial conditions or cash flows.

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

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

High winds and lack of precipitation increase the risk of wildfires resulting from the Company's infrastructure or for which the Company may otherwise have responsibility. The risk of wildfires is addressed primarily through asset management programs for natural gas transmission and distribution operations, and asset management, storm hardening, and vegetation management programs for electric utilities, but there can be no assurance that these measures will fully mitigate the risk. If it is found to be responsible for such a fire, the Company could suffer material 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, access to capital, financial condition and results of operations including its reputation with customers, regulators, governments and financial markets. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

Changes in Environmental Legislation

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

Changes to GHG emissions standards and air emissions standards could adversely affect Emera's operations and financial performance.

Both the Government of Nova Scotia and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix, reductions in GHG emissions, as well as the goal to phase out coal-fired electricity generation by 2030. Failure to meet such goals by 2030 could result in material fines, penalties, other sanctions and adverse reputational impacts. NSPI continues to work with both the provincial and federal governments on measures to seek to address their carbon reduction goals. 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, renewable natural gas projects, and support of public policy initiatives that address the effects of climate change.

In 2023, the United States Environmental Protection Agency proposed new carbon emission standards for fossil fuel-fired power plants and the Government of Canada released draft Clean Electricity Regulations which propose limitations on the use of natural gas generation. Until final rules are issued, it is not certain what the impact will be on the Company and its operations.

These and other legislative or regulatory changes could influence decisions regarding capital investment, 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.

Per- and polyfluoroalkyl substances (“PFAS”) are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. The Company does not manufacture PFAS but because these emerging contaminants of concern are so ubiquitous in products and the environment, it may impact Emera’s operations. Changes in environmental laws and regulations related to PFAS could result in new costs or obligations for investigation and cleanup and change the Company’s strategy for land acquisition for projects such as solar generation.

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 assess compliance.

Cybersecurity Risk

Emera is exposed to potential risks related to cyberattacks and unauthorized access. The Company relies on IT systems, cloud infrastructure, third-party service providers and the diligence of its team members to effectively manage and safely operate its assets. This includes controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other enterprise systems. As the Company operates critical assets, it may be at greater risk of cyberattacks, which could include those from nation-state cyber threat actors. Major emerging and ongoing global conflicts may also elevate this risk.

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

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

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

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

Public Health Risk

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

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

Energy Consumption Risk

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

Foreign Exchange Risk

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

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

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

Liquidity and Capital Market Risk

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs could be financed through internally generated cash flows, asset sales, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to meet 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 various market analysts, including credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in PP&E and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

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

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

General Economic Risk

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

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

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

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Market Risk".

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

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

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, increased demand for renewable energy inputs, risk of cost overruns, ensuring compliance with operating and environmental requirements and other events within or beyond the Company's control. The Company's projects may also require approvals and permits at the federal, provincial, state, regional and local levels. There is no assurance that Emera will be able to obtain the necessary project approvals or applicable permits or receive regulatory approval to recover the costs in rates.

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

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

Counterparty Risk

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

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

Country Risk

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

Supply Chain Risk

Emera's ability to meet customer energy requirements, respond to storm-related disruptions and execute on our capital program in a cost-effective and timely manner are dependent on maintaining an efficient supply chain. Domestic and global supply chain issues may delay the delivery or result in shortages of certain materials, equipment and other resources that are critical to the Company's operations. These disruptions may be further exacerbated by inflationary pressures, labour shortages, government incentives increasing demand for clean energy projects, and the impact of international conflicts, tariffs, or other trade restrictions. Failure to eliminate or manage supply chain constraints may impact the availability and cost of items and labour that are necessary to support operations and capital investment. Emera continues to monitor the situation and seeks to mitigate the impacts of supply chain risk by securing alternative suppliers, third party risk management, modifying design standards, and adjusting the timing of work.

Commodity Price Risk

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

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

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

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

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

To measure commodity price risk exposure, Emera Energy employs a number of controls and processes, including an estimated VaR analysis of its exposures. The VaR amount represents an estimate of the potential change in FV 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 and the Grand Bahama Power Company Limited Union Employees' Pension Plan. The cost of providing these benefit plans varies depending on plan provisions, interest rates, inflation, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, contributions to the plans and the pension and post-retirement liabilities) and expectations around future salary growth, inflation and mortality. Three of the largest drivers of cost are investment performance, interest rates and inflation, which are affected by global financial and capital markets. Depending on future interest rates and future inflation and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could adversely affect Emera's cash flows, financial condition and operations.

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

Labour Risk

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

Approximately 30 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labour disruption.

IT Risk

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

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

Income Tax Risk

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

System Operating and Maintenance Risks

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

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

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

Uninsured Risk

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities and to provide indemnity in the event of liability to third parties. This is consistent with Emera's risk management policies. Certain facilities, in particular coal and other thermal generation, may, over time, become more difficult (or uneconomic) to insure as a result of the impact of global climate change. Refer to "Global Climate Change Risk – Markets". There are certain elements of Emera's operations which are not insured. These include a significant portion of its electric utilities' transmission and distribution assets and its gas utilities' 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 manages its insured risk by aligning insurance limits 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. Risk management policies and practices are overseen by the Board. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company. This includes establishment of the ERMC, whose responsibilities include preparing an updated risk dashboard and heat map presented at regular meetings of the Board’s Risk and Sustainability Committee. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks.

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

The Company recognizes the FV 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 if the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, change in the FV of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Where documentation or effectiveness requirements are not met, the derivatives are recognized at FV with any changes in FV 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 FV 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. TEC has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases that ended on December 31, 2022 and was extended through December 31, 2024 as a result of TEC’s 2021 rate case settlement agreement.

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

Derivative Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars		**December 31 2023**		December 31 2022
Regulatory Deferral:				
Derivative instrument assets (1)	**$**	**16**	$	238
Derivative instrument liabilities (2)		**(76)**		(25)
Regulatory assets (1)		**88**		30
Regulatory liabilities (2)		**(17)**		(230)
Net asset	**$**	**11**	$	13
HFT Derivatives:				
Derivative instrument assets (1)	**$**	**202**	$	153
Derivatives instruments liabilities (2)		**(421)**		(1,025)
Net liability	**$**	**(219)**	$	(872)
Other Derivatives:				
Derivative instrument assets (1)	**$**	**22**	$	5
Derivatives instruments liabilities (2)		**(7)**		(28)
Net asset (liability)	**$**	**15**	$	(23)

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

Realized and Unrealized Gains (Losses) Recognized in Net Income

For the millions of dollars		Year ended December 31 **2023**		 2022
Regulatory Deferral:				
Regulated fuel for generation and purchased power (1)	**$**	**62**	$	210
HFT Derivatives:				
Non-regulated operating revenues	**$**	**1,037**	$	64
Other Derivatives:				
OM&G	**$**	**(9)**	$	(22)
Other income, net		**17**		(24)
Net gains (losses)	**$**	**8**	$	(46)
Total net gains	**$**	**1,107**	$	228

(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.

For the year ended December 31, 2023, unrealized gains of $2 million (2022 – $2 million), have been reclassified out of AOCI into interest expense.

As at		**December 31, 2023**		December 31, 2022
millions of dollars		**Interest rate hedge**		Interest rate hedge
Total unrealized gain in AOCI – net of tax	**$**	**14**	$	16

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 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, 2023 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, 2023, 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 reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations ("ARO"), and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.

Rate Regulation

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

As at December 31, 2023, the Company had recorded $3,105 million (2022 – $3,620 million) of regulatory assets and $1,772 million (2022 – $2,273 million) of regulatory liabilities.

Accumulated Reserve – Cost of Removal

TEC, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E upon retirement that are not legally required. The companies accrue for COR over the life of the related assets based on depreciation studies approved by their respective regulators. Costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. As at December 31, 2023, the balance of the Accumulated reserve – COR within regulatory liabilities was $849 million (2022 – $895 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.

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

The Company's accounting policy is to amortize the net actuarial gain or loss that exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period. For the largest plans this is currently 8.0 years (8.4 years for 2023 benefit cost) for Canadian plans and a weighted average of 11.5 years for United States plans. The Company's use of smoothed asset values reduces volatility related to 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:

	2023		2022	
	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	**5.55%**	**7.05%**	2.78%	6.50%
TECO Energy Group Supplemental Executive Retirement Plan (1)	**5.45%/5.31%**	**N/A**	2.35/5.33%	N/A
TECO Energy Group Benefit Restoration Plan (1)	**5.48/5.30/5.49%**	**N/A**	2.27/4.19/5.48%	N/A
TECO Energy Post-retirement Health and Welfare Plan	**5.53%/6.14%**	**N/A**	2.84%	N/A
New Mexico Gas Company Retiree Medical Plan	**5.55%**	**2.50%**	2.85%	1.50%
NSPI	**5.17%, 5.19%**	**6.25%**	3.25%, 3.48%	5.75%
GBPC Salaried	**5.75%**	**6.00%**	5.75%	6.00%
GBPC Union	**5.75%**	**5.35%**	5.75%	5.35%

(1) The discount rate 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 $43 million in 2023 (2022 – $64 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 2023 benefit cost of $0.5 million and $2.5 million, respectively (2022 – $0.5 million and $1 million).

Unbilled Revenue

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for other Emera utilities. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of estimates included in determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2023, unbilled revenues totalled $363 million (2022 – $424 million) on total regulated operating revenues of $7,235 million (2022 – $7,154 million).

PP&E

PP&E represents 62 per cent of total assets on the Company's balance sheet and includes 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 depreciable assets in each category. The service lives of regulated PP&E are determined based on depreciation studies and require appropriate regulatory approval. Due to the magnitude of the Company's PP&E, changes in estimated depreciation rates can have a material impact on depreciation expense and accumulated depreciation.

Depreciation expense was $1,019 million for the year ended December 31, 2023 (2022 – $927 million).

Goodwill Impairment Assessments

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated FV of identifiable assets acquired, and liabilities assumed at the acquisition date.

Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. Application of the goodwill impairment test requires management judgment on significant assumptions and estimates. When assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

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

As of December 31, 2023, $5,868 million (2022 – $6,009 million) of Emera's goodwill represents the excess of the acquisition purchase price for TECO Energy (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q4 2023, qualitative assessments were performed for NMGC and PGS, given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2022 and Q4 2019, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result no impairment charges were recognized.

As of December 31, 2023, the Company had goodwill with a total carrying amount of $5,871 million (December 31, 2022 – $6,012 million). The change in the carrying value of goodwill from 2022 to 2023 was a result of the effect of the FX translation of Emera's foreign affiliates.

In Q4 2022, as a result of a quantitative assessment, the Company recorded a goodwill impairment charge of $73 million, reducing the GBPC goodwill balance to nil as at December 31, 2022. For further detail, refer to note 22 in the consolidated financial statements.

Long-Lived Assets Impairment Assessments

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 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 FV.

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 results of operations for significant/indefinite future periods and current and expected market conditions in such periods. Markets can experience significant uncertainties. Estimates based on the Company's assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which consider external factors and market forces, as of the end of each reporting period. Assumptions made by management are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

As at December 31, 2023, there were no indications of impairment of Emera's long-lived assets. No impairment charges were recognized in either 2023 or 2022.

Income Taxes

Income taxes are determined based on 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 income tax assets will be recovered from future taxable income is assessed, and assumptions are made about expected timing of reversal of deferred income tax assets and liabilities. Uncertainty associated with application of tax statutes and regulations and outcomes of tax audits and appeals, requires that judgments and estimates be made in the accrual process and in 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 accounting estimates related to income taxes are critical estimates. Realization of deferred income tax assets depends on the generation of sufficient taxable income, both operating and capital, in future periods. A change in estimated valuation allowance could have a material impact on reported assets and results of operations. Administrative actions of tax authorities, changes in tax law or regulation, and 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 income tax assets.

Asset Retirement Obligations

Measurement of the FV of AROs requires the Company to make reasonable estimates concerning the method and timing of settlement associated with 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 remediation of generation, transmission, distribution and pipeline assets.

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

Some of the Company’s transmission and distribution assets may have conditional AROs that are not recognized in the consolidated financial statements as the FV of these obligations could not be reasonably estimated given 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 FV when an amount can be determined.

As at December 31, 2023, AROs recorded on the balance sheet were $192 million (2022 – $174 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $426 million (2022 – $429 million), which will be incurred between 2023 and 2061. The majority of these costs will be incurred between 2028 and 2050.

Financial Instruments

The Company is required to determine the FV of all derivatives except those that qualify for the normal purchase, normal sale exception. FV 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. FV 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 FV hierarchy. The FV 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 FV. FV is 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

Future Accounting Pronouncements

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

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The standard enhances the transparency, decision usefulness and effectiveness of income tax disclosures by requiring consistent categories and greater disaggregation of information in the reconciliation of income taxes computed using the enacted statutory income tax rate to the actual income tax provision and effective income tax rate, as well as the disaggregation of income taxes paid (refunded) by jurisdiction. The standard also requires disclosure of income (loss) before provision for income taxes and income tax expense (recovery) in accordance with U.S. Securities and Exchange Commission Regulation S-X 210.4-08(h), Rules of General Application – General Notes to Financial Statements: Income Tax Expense, and the removal of disclosures no longer considered cost beneficial or relevant. The guidance will be effective for annual reporting periods beginning after December 15, 2024, and interim periods within annual reporting periods beginning after December 15, 2025. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued ASU 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance will be effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied retrospectively. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q4 2023**	Q3 2023	Q2 2023	Q1 2023	Q4 2022	Q3 2022	Q2 2022	Q1 2022
Operating revenues	**$ 1,972**	$ 1,740	$ 1,418	$ 2,433	$ 2,358	$ 1,835	$ 1,380	$ 2,015
Net income (loss) attributable to common shareholders	**$ 289**	$ 101	$ 28	$ 560	$ 483	$ 167	$ (67)	$ 362
Adjusted net income	**$ 175**	$ 204	$ 162	$ 268	$ 249	$ 203	$ 156	$ 242
EPS – basic	**$ 1.04**	$ 0.37	$ 0.10	$ 2.07	$ 1.80	$ 0.63	$ (0.25)	$ 1.38
EPS – diluted	**$ 1.04**	$ 0.37	$ 0.10	$ 2.07	$ 1.80	$ 0.63	$ (0.25)	$ 1.38
Adjusted EPS – basic	**$ 0.63**	$ 0.75	$ 0.60	$ 0.99	$ 0.93	$ 0.76	$ 0.59	$ 0.92

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

Exhibit 99.3

EMERA INCORPORATED

Consolidated Financial Statements

December 31, 2023 and 2022

Exhibit 99.3

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 26, 2024

“Scott Balfour”
President and Chief Executive Officer

“Gregory Blunden”

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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, 2023 and 2022, 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, 2023 and 2022, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2023, 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 6 of the consolidated financial statements, the Company has $3.1 billion in regulatory assets and $1.8 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, but not limited to, property, plant and equipment (“PP&E”), 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 return on costs incurred, of the potential disallowance of part of the cost incurred, or of the probable refund of gains or amounts previously collected from 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, PP&E, 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 or refund 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, gains or amounts previously collected from customers 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 (“FV”) measurement of derivative financial instruments

Description of the Matter	Held-for-trading (“HFT”) derivative assets of $348 million and liabilities of $567 million, disclosed in note 15 to the consolidated financial statements, are measured at FV. The Company recognized $1,037 million in realized and unrealized gains 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 FV of the contracts. In determining the FV 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. These assumptions have a significant impact on the FV 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 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 FV 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 FV of derivatives.

/s/ Ernst & Young LLP
Chartered Professional Accountants

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

Halifax, Canada
February 26, 2024

Exhibit 99.3

Emera Incorporated
Consolidated Statements of Income

For the millions of dollars (except per share amounts)	Year ended December 31 **2023**	2022
Operating revenues		
Regulated electric	**$ 5,746**	$ 5,473
Regulated gas	**1,489**	1,681
Non-regulated	**328**	434
Total operating revenues (note 5)	**7,563**	7,588
Operating expenses		
Regulated fuel for generation and purchased power	**1,881**	2,171
Regulated cost of natural gas	**527**	800
Operating, maintenance and general expenses ("OM&G")	**1,879**	1,596
Provincial, state, and municipal taxes	**433**	367
Depreciation and amortization	**1,049**	952
GBPC Impairment charge (note 22)	**-**	73
Total operating expenses	**5,769**	5,959
Income from operations	**1,794**	1,629
Income from equity investments (note 7)	**146**	129
Other income, net (note 8)	**158**	145
Interest expense, net (note 9)	**925**	709
Income before provision for income taxes	**1,173**	1,194
Income tax expense (note 10)	**128**	185
Net income	**1,045**	1,009
Non-controlling interest in subsidiaries	**1**	1
Preferred stock dividends	**66**	63
Net income attributable to common shareholders	**$ 978**	$ 945
Weighted average shares of common stock outstanding (in millions) (note 12)		
Basic	**274**	266
Diluted	**274**	266
Earnings per common share (note 12)		
Basic	**$ 3.57**	$ 3.56
Diluted	**$ 3.57**	$ 3.55
Dividends per common share declared	**$ 2.7875**	$ 2.6775

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

Emera Incorporated
Consolidated Statements of Comprehensive Income

For the millions of dollars	Year ended December 31 **2023**	 2022
Net income	**$ 1,045**	$ 1,009
Other comprehensive (loss) income, net of tax		
Foreign currency translation adjustment (1)	**(270)**	629
Unrealized gains (losses) on net investment hedges (2) (3)	**38**	(97)
Cash flow hedges – reclassification adjustment for gains included in income (4)	**(2)**	(2)
Unrealized losses on available-for-sale investment	**-**	(1)
Net change in unrecognized pension and post-retirement benefit obligation (5)	**(39)**	24
Other comprehensive (loss) income (6)	**(273)**	553
Comprehensive income	**772**	1,562
Comprehensive income attributable to non-controlling interest	**1**	1
Comprehensive Income of Emera Incorporated	**$ 771**	$ 1,561

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

1) Net of tax recovery of $7 million for the year ended December 31, 2023 (2022 – $7 million expense).
2) The Company has designated $1.2 billion United States dollar (USD) denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations.
3) Net of tax expense of nil for the year ended December 31, 2023 (2022 – $6 million recovery).
4) Net of tax expense of nil for the year ended December 31, 2023 (2022 – $1 million recovery).
5) Net of tax expense of $1 million for the year ended December 31, 2023 (2022 – $1 million expense).
6) Net of tax recovery of $6 million for the year ended December 31, 2023 (2022 – $1 million expense).

Emera Incorporated
Consolidated Balance Sheets

As at millions of dollars		December 31 2023		December 31 2022
Assets				
Current assets				
Cash and cash equivalents	$	**567**	$	310
Restricted cash (note 32)		**21**		22
Inventory (note 14)		**790**		769
Derivative instruments (notes 15 and 16)		**174**		296
Regulatory assets (note 6)		**339**		602
Receivables and other current assets (note 18)		**1,817**		2,897
		3,708		4,896
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $9,994 and $9,574, respectively (note 20)		**24,376**		22,996
Other assets				
Deferred income taxes (note 10)		**208**		237
Derivative instruments (notes 15 and 16)		**66**		100
Regulatory assets (note 6)		**2,766**		3,018
Net investment in direct finance and sales type leases (note 19)		**621**		604
Investments subject to significant influence (note 7)		**1,402**		1,418
Goodwill (note 22)		**5,871**		6,012
Other long-term assets (note 32)		**462**		461
		11,396		11,850
Total assets	$	**39,480**	$	39,742
Liabilities and Equity				
Current liabilities				
Short-term debt (note 23)	$	**1,433**	$	2,726
Current portion of long-term debt (note 25)		**676**		574
Accounts payable		**1,454**		2,025
Derivative instruments (notes 15 and 16)		**386**		888
Regulatory liabilities (note 6)		**168**		495
Other current liabilities (note 24)		**427**		579
		4,544		7,287
Long-term liabilities				
Long-term debt (note 25)		**17,689**		15,744
Deferred income taxes (note 10)		**2,352**		2,196
Derivative instruments (notes 15 and 16)		**118**		190
Regulatory liabilities (note 6)		**1,604**		1,778
Pension and post-retirement liabilities (note 21)		**265**		281
Other long-term liabilities (note 7 and 26)		**820**		825
		22,848		21,014
Equity				
Common stock (note 11)		**8,462**		7,762
Cumulative preferred stock (note 28)		**1,422**		1,422
Contributed surplus		**82**		81
Accumulated other comprehensive income ("AOCI') (note 13)		**305**		578
Retained earnings		**1,803**		1,584
Total Emera Incorporated equity		**12,074**		11,427
Non-controlling interest in subsidiaries (note 29)		**14**		14
Total equity		**12,088**		11,441
Total liabilities and equity	$	**39,480**	$	39,742

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

Exhibit 99.3

Emera Incorporated
Consolidated Statements of Cash Flows

For the millions of dollars	Year ended December 31 2023	2022
Operating activities		
Net income	**$ 1,045**	$ 1,009
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**1,060**	959
Income from equity investments, net of dividends	**(22)**	(61)
Allowance for funds used during construction ("AFUDC") – equity	**(38)**	(52)
Deferred income taxes, net	**97**	152
Net change in pension and post-retirement liabilities	**(68)**	(48)
NSPI Fuel adjustment mechanism ("FAM")	**(88)**	(162)
Net change in Fair Value ("FV") of derivative instruments	**(666)**	206
Net change in regulatory assets and liabilities	**554**	(471)
Net change in capitalized transportation capacity	**434**	(445)
GBPC impairment charge	**-**	73
Other operating activities, net	**28**	(13)
Changes in non-cash working capital (note 30)	**(95)**	(234)
Net cash provided by operating activities	**2,241**	913
Investing activities		
Additions to PP&E	**(2,937)**	(2,596)
Other investing activities	**20**	27
Net cash used in investing activities	**(2,917)**	(2,569)
Financing activities		
Change in short-term debt, net	**(66)**	1,028
Proceeds from short-term debt with maturities greater than 90 days	**548**	544
Repayment of short-term debt with maturities greater than 90 days	**(1,086)**	(680)
Proceeds from long-term debt, net of issuance costs	**1,932**	784
Retirement of long-term debt	**(151)**	(367)
Net (repayments) proceeds under committed credit facilities	**(96)**	511
Issuance of common stock, net of issuance costs	**424**	277
Dividends on common stock	**(488)**	(472)
Dividends on preferred stock	**(66)**	(63)
Other financing activities	**(12)**	(7)
Net cash provided by financing activities	**939**	1,555
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(7)**	16
Net increase (decrease) in cash, cash equivalents, and restricted cash	**256**	(85)
Cash, cash equivalents, and restricted cash, beginning of year	**332**	417
Cash, cash equivalents, and restricted cash, end of year	**$ 588**	$ 332
Cash, cash equivalents, and restricted cash consists of:		
Cash	**$ 559**	$ 302
Short-term investments	**8**	8
Restricted cash	**21**	22
Cash, cash equivalents, and restricted cash	**$ 588**	$ 332

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 dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	Non-Controlling Interest	Total Equity
Balance, December 31, 2022	$ 7,762	$ 1,422	$ 81	$ 578	$ 1,584	$ 14	$ 11,441
Net income of Emera Inc.	-	-	-	-	1,044	1	1,045
Other comprehensive loss, net of tax recovery of $6 million	-	-	-	(273)	-	-	(273)
Dividends declared on preferred stock (note 28)	-	-	-	-	(66)	-	(66)
Dividends declared on common stock ($2.7875/share)	-	-	-	-	(759)	-	(759)
Issued under the at-the-market program ("ATM"), net of after-tax issuance costs	397	-	-	-	-	-	397
Issued under the Dividend Reinvestment Program ("DRIP"), net of discount	272	-	-	-	-	-	272
Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSPP")	31	-	1	-	-	-	32
Other	-	-	-	-	-	(1)	(1)
Balance, December 31, 2023	**$ 8,462**	**$ 1,422**	**$ 82**	**$ 305**	**$ 1,803**	**$ 14**	**$ 12,088**
Balance, December 31, 2021	$ 7,242	$ 1,422	$ 79	$ 25	$ 1,348	$ 34	$ 10,150
Net income of Emera Inc.	-	-	-	-	1,008	1	1,009
Other comprehensive income, net of tax expense of $1 million	-	-	-	553	-	-	553
Dividends declared on preferred stock (note 28)	-	-	-	-	(63)	-	(63)
Dividends declared on common stock ($2.6775/share)	-	-	-	-	(709)	-	(709)
Issued under the ATM, net of after-tax issuance costs	248	-	-	-	-	-	248
Issued under the DRIP, net of discount	238	-	-	-	-	-	238
Senior management stock options exercised and ECSPP	34	-	2	-	-	-	36
Disposal of non-controlling interest of Dominica Electricity Services Ltd ("Domlec")	-	-	-	-	-	(20)	(20)
Other	-	-	-	-	-	(1)	(1)
Balance, December 31, 2022	$ 7,762	$ 1,422	$ 81	$ 578	$ 1,584	$ 14	$ 11,441

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

Emera Incorporated
Notes to the Consolidated Financial Statements
As at December 31, 2023 and 2022

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, 2023, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), a vertically integrated regulated electric utility, serving approximately 840,000 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 549,000 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, developed by Nalcor Energy. ENL's two investments are:
        - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion transmission project, including AFUDC; and
        - a 31 per cent equity interest in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador.

- Gas Utilities and Infrastructure, which includes:
    - Peoples Gas System Inc. ("PGS"), a regulated gas distribution utility, serving approximately 490,000 customers across Florida. Effective January 1, 2023, Peoples Gas System ceased to be a division of Tampa Electric Company and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.;
    - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 540,000 customers in New Mexico;
    - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership ("Repsol Energy"), which expires in 2034;
    - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida; and
    - a 12.9 per cent equity 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.

- 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 134,000 customers;
    - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 19,000 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.

- Emera's other reportable segment includes investments in energy-related non-regulated companies which include:
  - 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 660 MW pumped storage hydroelectric facility in northwestern Massachusetts.
  - Emera US Finance LP ("Emera Finance") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
  - Block Energy LLC (previously Emera Technologies LLC), a wholly owned technology company focused on finding ways to deliver renewable 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.

Basis of Presentation

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP") and in the opinion of management, 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 ("CAD"), unless otherwise indicated.

Principles of Consolidation

These consolidated financial statements include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. 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 VIE that most significantly impacts its economic performance and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. 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. For further details on VIEs, refer to note 32.

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 PP&E, regulatory assets, regulated fuel for generation and purchased power, or 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 reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations ("ARO"), and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. Rates are designed to recover prudently incurred costs of providing 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 6.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are converted to CAD 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 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 USD denominated debt held in CAD functional currency companies as hedges of net investments in USD denominated foreign operations. The change in the carrying amount of these investments, measured at exchange rates in effect at the balance sheet date is recorded in Other Comprehensive Income ("OCI").

Revenue Recognition

Regulated Electric and Gas Revenue:
Electric and gas 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 and gas are delivered to customers over time as the customer simultaneously receives and consumes the benefits. Electric and gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity and gas are recognized at rates approved by the respective regulators 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, electricity and gas delivered to customers, but not billed, is estimated and corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the megawatt hours ("MWh") or 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 energy demand, weather, line losses 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 the contract are satisfied and are presented on a net basis reflecting the nature of 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 the terms of the 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.

Franchise Fees and Gross Receipts

TEC 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 TEC 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.

PP&E

PP&E is recorded at original cost, including AFUDC or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units, are included in "PP&E" on the Consolidated Balance Sheets. When units of regulated PP&E 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 PP&E occurs, gains and losses are included in income as the dispositions occur.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, 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 and major maintenance projects that do not increase overall life of the related assets are expensed as incurred. 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 regulatory approval.

Intangible assets, which are included in “PP&E” on the Consolidated Balance Sheets, 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 FV 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 (“FX”). Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. 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 a qualitative assessment and determines it is more likely than not that its FV 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 FV of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its FV, an impairment loss is recorded. Management estimates the FV of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach uses a discounted cash flow analysis which relies on management’s best estimate of the reporting unit’s 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. For the market approach, management estimates FV based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the FV of a reporting unit using an income approach include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting unit’s net operating loss (“NOL”) and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera’s reporting units.

As of December 31, 2023, $5,868 million of Emera’s goodwill represents the excess of the acquisition purchase price for TECO Energy (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q4 2023, qualitative assessments were performed for NMGC and PGS given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2022 and Q4 2019, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result, no impairment charges were recognized.

In Q4 2022, as a result of a quantitative assessment, the Company recorded a goodwill impairment charge of $73 million, reducing the GBPC goodwill balance to nil as at December 31, 2022. For further details, 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 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 income tax assets will be recovered from future taxable income is assessed and assumptions are made about the expected timing of reversal of deferred income tax assets and liabilities. If management subsequently determines it is likely that some or all of a deferred income tax asset will not be realized, 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 on regulated assets by TEC, PGS and NMGC are deferred and amortized as required by regulatory practices.

TEC, PGS, NMGC and BLPC 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 regulators. 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 detail, refer to note 10.

Derivatives and Hedging Activities

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

The Company recognizes the FV 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 if the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, change in the FV of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Where documentation or effectiveness requirements are not met, the derivatives are recognized at FV with any changes in FV 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 FV 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. TEC has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases that ended on December 31, 2022 and was extended through December 31, 2024 as a result of TEC's 2021 rate case settlement agreement.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in FV 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 non-regulated operating revenues, fuel for generation and purchased power, other expenses, inventory, and OM&G, 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 FV 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".

Leases

The Company determines whether a contract contains a lease at inception by evaluating whether 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 for annual requirements to purchase wind and hydro energy over varying contract lengths which 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 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 FV 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.

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 recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Management estimates credit losses related to accounts receivable by 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.

Inventory

Fuel and materials inventories are valued at the lower of weighted-average cost or net realizable value, unless evidence indicates 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 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 FV. 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.

As at December 31, 2023, there are no indications of impairment of Emera's long-lived assets. No impairment charges related to long-lived assets were recognized in 2023 or 2022.

Equity Method Investments:
The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the FV of these investments to their carrying values, if a FV assessment was completed, or by reviewing for the presence of impairment indicators. 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 FV. No impairment of equity method investments was required in either 2023 or 2022.

Financial Assets:
Equity investments, other than those accounted for under the equity method, are measured at FV, with changes in FV recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable FV 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 2023 or 2022.

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 FV of 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 that are not recognized in the consolidated financial statements, as the FV of these obligations could not be reasonably estimated, given 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 FV in the period in which an amount can be determined.

Cost of Removal ("COR")

TEC, PGS, NMGC and NSPI recognize non-ARO 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 PP&E 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 FV-based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated FV 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 FV and re-measured at FV 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 unamortized gains and losses and past service costs in "AOCI" or "Regulatory assets" on the Consolidated Balance Sheets. 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. For further detail, refer to note 21.

2. FUTURE ACCOUNTING PRONOUNCEMENTS

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

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The standard enhances the transparency, decision usefulness and effectiveness of income tax disclosures by requiring consistent categories and greater disaggregation of information in the reconciliation of income taxes computed using the enacted statutory income tax rate to the actual income tax provision and effective income tax rate, as well as the disaggregation of income taxes paid (refunded) by jurisdiction. The standard also requires disclosure of income (loss) before provision for income taxes and income tax expense (recovery) in accordance with U.S. Securities and Exchange Commission Regulation S-X 210.4-08(h), Rules of General Application – General Notes to Financial Statements: Income Tax Expense, and the removal of disclosures no longer considered cost beneficial or relevant. The guidance will be effective for annual reporting periods beginning after December 15, 2024, and interim periods within annual reporting periods beginning after December 15, 2025. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued ASU 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance will be effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied retrospectively. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

3. DISPOSITIONS

On March 31, 2022, Emera completed the sale of its 51.9 per cent interest in Domlec for proceeds which approximated its carrying value. Domlec was included in the Company's Other Electric reportable segment up to its date of sale. The sale did not have a material impact on earnings.

4. 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.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2023							
Operating revenues from external customers (1)	$ 3,548	$ 1,671	$ 1,510	$ 526	$ 308	$ -	$ **7,563**
Inter-segment revenues (1)	8	-	14	-	31	(53)	**-**
Total operating revenues	3,556	1,671	1,524	526	339	(53)	**7,563**
Regulated fuel for generation and purchased power	920	699	-	275	-	(13)	**1,881**
Regulated cost of natural gas	-	-	527	-	-	-	**527**
OM&G	830	384	405	130	151	(21)	**1,879**
Provincial, state and municipal taxes	289	45	91	3	5	-	**433**
Depreciation and amortization	571	276	126	68	8	-	**1,049**
Income from equity investments	-	109	21	4	12	-	**146**
Other income, net	69	32	11	7	20	19	**158**
Interest expense, net (2)	271	170	129	23	332	-	**925**
Income tax expense (recovery)	117	(9)	64	-	(44)	-	**128**
Non-controlling interest in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	66	-	**66**
Net income (loss) attributable to common shareholders	$ 627	$ 247	$ 214	$ 37	$ (147)	$ -	$ **978**
Capital expenditures	$ 1,736	$ 450	$ 664	$ 63	$ 8	$ -	$ **2,921**
As at December 31, 2023							
Total assets	$ 21,119	$ 8,634	$ 7,735	$ 1,311	$ 1,938	$ (1,257)	$ **39,480**
Investments subject to significant influence	$ -	$ 1,236	$ 118	$ 48	$ -	$ -	$ **1,402**
Goodwill	$ 4,628	$ -	$ 1,240	$ -	$ 3	$ -	$ **5,871**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, 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 of $95 million for the year ended December 31, 2023, between the Florida Electric Utility, Gas Utilities and Infrastructure and Other segments.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2022							
Operating revenues from external customers (1)	$ 3,280	$ 1,675	$ 1,697	$ 518	$ 418	$ -	$ **7,588**
Inter-segment revenues (1)	7	-	7	-	22	(36)	**-**
Total operating revenues	3,287	1,675	1,704	518	440	(36)	**7,588**
Regulated fuel for generation and purchased power	1,086	803	-	290	-	(8)	**2,171**
Regulated cost of natural gas	-	-	800	-	-	-	**800**
OM&G	625	338	365	123	156	(11)	**1,596**
Provincial, state and municipal taxes	235	43	83	3	3	-	**367**
Depreciation and amortization	507	259	118	61	7	-	**952**
Income from equity investments	-	87	21	4	17	-	**129**
Other income (expenses), net	68	24	13	-	23	17	**145**
Interest expense, net (2)	185	136	81	19	288	-	**709**
GBPC impairment charge	-	-	-	73	-	-	**73**
Income tax expense (recovery)	121	(8)	70	-	2	-	**185**
Non-controlling interest in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	63	-	**63**
Net income (loss) attributable to common shareholders	$ 596	$ 215	$ 221	$ (48)	$ (39)	$ -	$ **945**
Capital expenditures	$ 1,425	$ 507	$ 574	$ 63	$ 6	$ -	$ **2,575**
As at December 31, 2022							
Total assets	$ 21,053	$ 8,223	$ 7,737	$ 1,337	$ 2,835	$ (1,443)	$ **39,742**
Investments subject to significant influence	$ -	$ 1,241	$ 128	$ 49	$ -	$ -	$ **1,418**
Goodwill	$ 4,739	$ -	$ 1,270	$ -	$ 3	$ -	$ **6,012**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, 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 of $ 13 million for the year ended December 31, 2022, between the Gas Utilities and Infrastructure and Other segments.

Geographical Information

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

For the millions of dollars	Year ended December 31 **2023**	 2022
United States	**5,310**	$ 5,346
Canada	**1,727**	1,725
Barbados	**389**	384
The Bahamas	**137**	122
Dominica	**-**	11
	$ 7,563	$ 7,588

Property Plant and Equipment:

As at millions of dollars	**December 31 2023**	December 31 2022
United States	**$ 18,588**	$ 17,382
Canada	**4,878**	4,689
Barbados	**576**	583
The Bahamas	**334**	342
	$ 24,376	$ 22,996

5. REVENUE

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

millions of dollars	Electric: Florida Electric Utility	Electric: Canadian Electric Utilities	Electric: Other Electric Utilities	Gas: Gas Utilities and Infrastructure	Other: Other	Other: Inter-Segment Eliminations	Total
For the year ended December 31, 2023							
Regulated Revenue							
Residential	$ 2,307	$ 910	$ 183	$ 724	$ -	$ -	$ 4,124
Commercial	1,083	463	285	425	-	-	2,256
Industrial	274	219	33	93	-	(13)	606
Other electric	395	41	7	-	-	-	443
Regulatory deferrals	(522)	-	12	-	-	-	(510)
Other (1)	19	38	6	199	-	(8)	254
Finance income (2)(3)	-	-	-	62	-		62
Regulated revenue	$ 3,556	$ 1,671	$ 526	$ 1,503	$ -	$ (21)	$ 7,235
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	96	-	96
Other non-regulated operating revenue	-	-	-	21	27	(23)	25
Mark-to-market (3)	-	-	-	-	216	(9)	207
Non-regulated revenue	$ -	$ -	$ -	$ 21	$ 339	$ (32)	$ 328
Total operating revenues	**$ 3,556**	**$ 1,671**	**$ 526**	**$ 1,524**	**$ 339**	**$ (53)**	**$ 7,563**
For the year ended December 31, 2022							
Regulated Revenue							
Residential	$ 1,799	$ 834	$ 184	$ 800	$ -	$ -	**$** 3,617
Commercial	869	427	282	461	-	-	2,039
Industrial	230	353	32	83	-	(7)	691
Other electric	398	28	6	-	-	-	432
Regulatory deferrals	(27)	-	6	-	-	-	(21)
Other (1)	18	33	8	283	-	(7)	335
Finance income (2)(3)	-	-	-	61	-	-	61
Regulated revenue	$ 3,287	$ 1,675	$ 518	$ 1,688	$ -	$ (14)	7,154
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	143	-	143
Other non-regulated operating revenue	-	-	-	16	16	(10)	22
Mark-to-market (3)	-	-	-	-	281	(12)	269
Non-regulated revenue	$ -	$ -	$ -	$ 16	$ 440	$ (22)	434
Total operating revenues	$ 3,287	$ 1,675	$ 518	$ 1,704	$ 440	$ (36)	$ 7,588

(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, 2023, the aggregate amount of the transaction price allocated to remaining performance obligations was $488 million (2022 – $450 million). This amount includes $134 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 2043.

6. 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, 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 dollars		**December 31 2023**		December 31 2022
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,233**	$	1,166
TEC capital cost recovery for early retired assets		**671**		674
NSPI FAM		**395**		307
Pension and post-retirement medical plan		**364**		369
Cost recovery clauses		**151**		707
Deferrals related to derivative instruments		**88**		30
Storm cost recovery clauses		**52**		138
Environmental remediations		**26**		27
Stranded cost recovery		**25**		27
NMGC winter event gas cost recovery		**-**		69
Other		**100**		106
	$	**3,105**	$	3,620
Current	**$**	**339**	$	602
Long-term		**2,766**		3,018
Total regulatory assets	**$**	**3,105**	$	3,620
Regulatory liabilities				
Accumulated reserve – COR		**849**		895
Deferred income tax regulatory liabilities		**830**		877
Cost recovery clauses		**32**		70
BLPC Self-insurance fund ("SIF") (note 32)		**29**		30
Deferrals related to derivative instruments		**17**		230
NMGC gas hedge settlements (note 18)		**-**		162
Other		**15**		9
	$	**1,772**	$	2,273
Current	**$**	**168**	$	495
Long-term		**1,604**		1,778
Total regulatory liabilities	**$**	**1,772**	$	2,273

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.

TEC 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 is 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. For further information, refer to “Big Bend Modernization Project” in the TEC section below.

NSPI FAM

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through regularly scheduled 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 and recovered from or returned to customers in subsequent periods.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at TEC, PGS and NMGC. It is included in rate base and earns a rate of return as permitted by the FPSC and NMPRC, as applicable. It is amortized over the remaining service life of plan participants.

Cost Recovery Clauses

These assets and liabilities are related to TEC, PGS and NMGC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or New Mexico Public Regulation Commission (“NMPRC”), as applicable, on a dollar-for-dollar basis in a subsequent period.

Deferrals Related to Derivative Instruments

This asset is primarily related to NSPI deferring changes in FV 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 the UARB. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, other income, inventory, or OM&G, depending on the nature of the item being economically hedged.

Storm Cost Recovery Clauses

TEC and PGS Storm Reserve:
The storm reserve is for hurricanes and other named storms that cause significant damage to TEC and PGS systems. As allowed by the FPSC, if charges to the storm reserve exceed the storm liability, the excess is to be carried as a regulatory asset. TEC 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 2022, TEC and PGS were impacted by Hurricane Ian. For further information, refer to “TEC Storm Reserve” in the Florida Electric Utility section below.

NSPI Storm Rider:
NSPI has a UARB approved storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the UARB for recovery of costs if major storm restoration expenses exceed approximately $10 million in a given year.

GBPC Storm Restoration:
This asset represents storm restoration costs 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 recovery of $15 million USD of 2019 costs related to Hurricane Dorian, over a five-year period from 2021 through 2025.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge. For further information, refer to "Storm Restoration Costs – Hurricane Matthew" in the GBPC section below.

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

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 ("PGAC"). On June 15, 2021, the NMPRC approved recovery of $108 million USD and related borrowing costs in customer rates over a period of 30 months from July 1, 2021, to December 31, 2023.

Accumulated Reserve – COR

This regulatory liability represents the non-ARO COR reserve in TEC, PGS, NMGC and NSPI. AROs represent the FV of estimated cash flows associated with the Company's legal obligation to retire its PP&E. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E 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.

NMGC Gas Hedge Settlements

This regulatory liability represents regulatory deferral of gas options exercised above strike price but settled subsequent to the period end. The value from cash settlement of these options flows to customers via the PGAC.

Other Regulatory Assets and Liabilities

Comprised of regulatory assets and liabilities that are not individually significant.

Regulatory Environments and Updates

Florida Electric Utility

TEC is regulated by the FPSC and is also subject to regulation by the Federal Energy Regulatory Commission. The FPSC sets rates at a level that allows utilities such as TEC 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 TEC, the FPSC or other interested parties.

TEC's approved regulated return on equity ("ROE") range for 2023 and 2022 was 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.20 per cent (2022 – 10.20 per cent) is used for the calculation of the return on investments for clauses.

Base Rates:
On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 million USD for 2026 and 2027, respectively. TEC's proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC's ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

Fuel Recovery and Other Cost Recovery Clauses:
TEC 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 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 subsequent periods.

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

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

Big Bend Modernization Project:
TEC invested $876 million USD, including $91 million USD of AFUDC, between 2018 and 2022 to modernize the Big Bend Power Station. The modernization project repowered Big Bend Unit 1 with natural gas combined-cycle technology and eliminated coal as this unit's fuel. As part of the modernization project, TEC in 2020 retired the Unit 1 components that would not be used in the modernized plant and did the same for Big Bend Unit 2 in 2021. TEC retired Big Bend Unit 3 in 2023 as it was in the best interests of the customers from an economic, environmental risk and operational perspective. On December 31, 2021, the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, of $636 million USD and $267 million USD in accumulated depreciation were reclassified to a regulatory asset on the balance sheet.

TEC's 2021 settlement agreement provides for cost recovery of the Big Bend Modernization project in two phases. The first phase was a revenue increase to cover the costs of the assets in service during 2022, among other items. The remainder of the project costs were recovered as part of the 2023 subsequent year adjustment. The settlement agreement also includes a new charge to recover the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, which are spread over 15 years, effective January 1, 2022. This recovery mechanism was authorized by and survives the term of the settlement agreement approved by the FPSC in 2021.

Storm Reserve:
In September 2022, TEC was impacted by Hurricane Ian, with $119 million USD of restoration costs charged against TEC's FPSC approved storm reserve. Total restoration costs charged to the storm reserve exceeded the reserve balance and have been deferred as a regulatory asset for future recovery.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the FPSC approved TEC's petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings.

Storm Protection Cost Recovery Clause and Settlement Agreement:
The Storm Protection Plan ("SPP") Cost Recovery Clause provides a process for Florida investor-owned utilities, including TEC, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. 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. A settlement agreement was approved on August 10, 2020, and TEC's cost recovery began in January 2021. The current approved plan addressed the years 2023, 2024 and 2025 and was approved by the FPSC on October 4, 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 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's approved regulated ROE range for 2023 and 2022 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 of approved rate base.

General Rate Application ("GRA"):
On February 2, 2023, the UARB approved the GRA settlement agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and further average increases of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB's established FAM process. It also established a storm rider and a demand-side management rider. On March 27, 2023, the UARB issued a final order approving the electricity rates effective on February 2, 2023.

Fuel Recovery:
For the period of 2020 through 2022, NSPI operated under a three-year fuel stability plan with no fuel rate adjustments related to the under-recovery of fuel and fuel-related costs in the period.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding FAM balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024.

Storm Rider:
The storm rider was effective as of the GRA decision date. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application. Total major storm restoration expense for 2023 was $31 million, of which $21 million was deferred to the storm rider.

Hurricane Fiona:
On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023, the $24 million is deferred to "Other long-term assets", pending UARB approval.

Maritime Link:
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. Any difference between the amounts recovered from customers through rates and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

Nova Scotia Cap-and-Trade ("Cap-and-Trade") Program:
As of December 31, 2022, the FAM included a cumulative $166 million in fuel costs related to the accrued purchase of emissions credits and $6 million related to credits purchased from provincial auctions. On March 16, 2023, the Province of Nova Scotia provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 period. As such, compliance costs accrued of $166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of $6 million were not refunded and no further costs were incurred to achieve compliance with the Cap-and-Trade Program.

Extra Large Industrial Active Demand Tariff:
On July 5, 2023, NSPI received approval from the UARB to change the methodology in which fuel cost recovery from an industrial customer is calculated. Due to significant volatility in commodity prices in 2022, the previous methodology did not result in a reasonable determination of the fuel cost to serve this customer. The change in methodology, effective January 1, 2022, results in a shifting of fuel costs from this industrial customer to the FAM. This adjustment was recorded in Q2 2023 resulting in a $51 million increase to the FAM regulatory asset and an offsetting decrease to unbilled revenue within Receivables and other current assets. This adjustment had minimal impact on earnings.

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 Nova Scotia Block ("NS Block") delivery obligations commenced on August 15, 2021 and delivery will continue over the next 35 years pursuant to the agreements.

In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion less $9 million of costs ($7 million after-tax) that would not have otherwise been recoverable if incurred by NSPI.

On October 4, 2023 and January 31, 2024, the UARB issued decisions providing clarification on remaining aspects of the Maritime Link holdback mechanism primarily relating to release of past and future holdback amounts and requirements to end the holdback mechanism. In these decisions, the UARB agreed with the Company's submission that $12 million ($8 million related to 2022 and $4 million relating to 2023) of the previously recorded holdback remain credited to NSPI's FAM, with the remainder released to NSPML and recorded in Emera's "Income from equity investments. NSPML did not record any additional holdback in Q4 2023. The UARB also confirmed that the holdback mechanism will cease once 90 per cent of NS Block deliveries are achieved for 12 consecutive months (subject to potential relief for planned outages or exceptional circumstances) and the net outstanding balance of previously underdelivered NS Block energy is less than 10 per cent of the contracted annual amount. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023.

On December 21, 2023, NSPML received approval to collect up to $164 million (2023 – $164 million) from NSPI for the recovery of costs associated with the Maritime Link in 2024; subject to a holdback of up to $4 million a month, as discussed above.

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 2023 and 2022 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.

Base Rates:
On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

The 2020 PGS rate case settlement provided the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

Fuel Recovery:
PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its PGAC. 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.

Recovery of Energy Conservation and Pipeline Replacement Programs:
The FPSC annually approves a conservation charge that is intended to permit PGS to recover prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are required by Florida law and approved and monitored by the FPSC. PGS also 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. The majority of cast iron and bare steel pipe has been removed from its system, 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.

NMGC’s approved ROE for 2023 and 2022 was 9.375 per cent on an allowed equity capital structure of 52 per cent.

Base Rates:
On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective Q4 2024. NMGC requested $49 million USD in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent.

Fuel Recovery:
NMGC recovers gas supply costs through a PGAC. This clause recovers 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 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. NMGC received approval of its PGAC Continuation in December 2020, for the four-year period ending December 2024.

Integrity Management Programs (“IMP”) Regulatory Asset:
A portion of NMGC’s annual spending on infrastructure is for 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 petitioned recovery of the regulatory asset in its rate case filed on December 13, 2021. On November 30, 2022, the NMPRC issued a Final Order that included approval of recovery of the IMP regulatory asset.

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Saint John 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 North America Canada Partnership. 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.

Other Electric Utilities

BLPC

BLPC is regulated by the Fair Trading Commission ("FTC"), under the Utilities Regulation (Procedural) Rules 2003. BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's approved regulated return on rate base was 10 per cent for 2023 and 2022.

Licenses:
BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

Base Rates:
In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the "Motion") and applied for a stay of the FTC's decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

On December 1, 2023, BLPC appealed certain aspects of the FTC's February 15 and November 20, 2023, decisions to the Supreme Court of Barbados in the High Court of Justice (the "Court") and requested that they be stayed. On December 11, 2023, the Court granted the stay. BLPC's position is that the FTC made errors of law and jurisdiction in their decisions and believes the success of the appeal is probable, and as a result, the adjustments to BLPC's final rates and rate base, including any adjustments to regulatory assets and liabilities, have not been recorded at this time.

Fuel Recovery:
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 calculation of the fuel charge is adjusted on a monthly basis and reported to the FTC for approval.

Clean Energy Transition Program ("CETP"):
On May 31, 2023, the FTC approved BLPC's application to establish an alternative cost recovery mechanism to recover prudently incurred costs associated with its CETP (the "Decision"). The mechanism is intended to facilitate the timely recovery between rate cases of costs associated with approved renewable energy assets. BLPC will be required to submit an individual application for the recovery of costs of each asset through the cost recovery mechanism, meeting the minimum criteria as set out in the Decision. On October 5, 2023, BLPC applied to the FTC to recover the costs of a battery storage system through the CETP.

Fuel Hedging:
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.

GBPC

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. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. GBPC's approved regulated return on rate base was 8.32 per cent for 2023 (2022 – 8.23 per cent).

Base Rates:
There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. 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 became effective April 1, 2022, allows for an increase in revenues of $3.5 million USD. The rates include a regulatory ROE of 12.84 per cent.

Fuel Recovery:
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.

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

Storm Restoration Costs – Hurricane Matthew:
As part of the recovery of costs incurred as a result of Hurricane Matthew, in 2016, 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. As part of its decision on GBPC's application for rate review, 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.

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of dollars	Carrying Value As at December 31 2023	2022	Equity Income For the year ended December 31 2023	2022	Percentage of Ownership 2023
LIL (1)	$ 747	$ 740	$ 63	$ 58	31.0
NSPML	489	501	46	29	100.0
M&NP (2)	118	128	21	21	12.9
Lucelec (2)	48	49	4	4	19.5
Bear Swamp (3)	-	-	12	17	50.0
	$ 1,402	$ 1,418	$ 146	$ 129	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.5 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) Emera has significant influence over the operating and financial decisions of these companies through Board representation and therefore, 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 $81 million (2022 – $95 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

Equity investments include a $10 million difference between the cost and the underlying FV 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 dollars	December 31 2023	2022
Balance Sheets		
Current assets	$ 21	$ 17
PP&E	1,473	1,517
Regulatory assets	272	265
Non-current assets	29	29
Total assets	$ 1,795	$ 1,828
Current liabilities	$ 48	$ 48
Long-term debt (1)	1,109	1,149
Non-current liabilities	149	130
Equity	489	501
Total liabilities and equity	$ 1,795	$ 1,828

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

8. OTHER INCOME, NET

For the millions of dollars	Year ended December 31 2023	2022
Interest income	$ 43	$ 25
AFUDC	38	52
Pension non-current service cost recovery	35	24
FX gains (losses)	20	(26)
TECO Guatemala Holdings award (1)	-	63
Other	22	7
	$ 158	$ 145

(1) On December 15, 2022, a payment of $63 million was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment in TGH, a wholly-owned subsidiary of TECO Energy.

9. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Year ended December 31 **2023**	2022
Interest on debt	**$ 954**	$ 727
Allowance for borrowed funds used during construction	**(16)**	(21)
Other	**(13)**	3
	$ 925	$ 709

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 dollars	**2023**	2022
Income before provision for income taxes	**$ 1,173**	$ 1,194
Statutory income tax rate	**29.0%**	29.0%
Income taxes, at statutory income tax rate	**340**	346
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(72)**	(70)
Tax credits	**(53)**	(18)
Foreign tax rate variance	**(36)**	(44)
Amortization of deferred income tax regulatory liabilities	**(33)**	(33)
Tax effect of equity earnings	**(15)**	(10)
GBPC impairment charge	**-**	21
Other	**(3)**	(7)
Income tax expense	**$ 128**	$ 185
Effective income tax rate	**11%**	15%

On August 16, 2022, the United States Inflation Reduction Act ("IRA") was signed into legislation. The IRA includes numerous tax incentives for clean energy, such as the extension and modification of existing investment and production tax credits for projects placed in service through 2024 and introduces new technology-neutral clean energy related tax credits beginning in 2025. As of December 31, 2023, the Company has recorded a $30 million (2022 - $9 million) regulatory liability on the Consolidated Balance Sheets in recognition of its obligation to pass the incremental tax benefits realized to customers.

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 dollars	**2023**	2022
Current income taxes		
Canada	**$ 26**	$ 25
United States	**5**	8
Deferred income taxes		
Canada	**93**	122
United States	**128**	252
Investment tax credits		
United States	**(29)**	(7)
Operating loss carryforwards		
Canada	**(93)**	(94)
United States	**(2)**	(121)
Income tax expense	**$ 128**	$ 185

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 dollars		2023		2022
Canada	$	**171**	$	173
United States		**964**		1,063
Other		**38**		(42)
Income before provision for income taxes	$	**1,173**	$	1,194

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

millions of dollars		2023		2022
Deferred income tax assets:				
Tax loss carryforwards	$	**1,195**	$	1,207
Tax credit carryforwards		**454**		415
Derivative instruments		**205**		45
Regulatory liabilities		**175**		264
Other		**372**		341
Total deferred income tax assets before valuation allowance		**2,401**		2,272
Valuation allowance		**(363)**		(312)
Total deferred income tax assets after valuation allowance	$	**2,038**	$	1,960
Deferred income tax (liabilities):				
PP&E	$	**(3,223)**	$	(2,981)
Derivative instruments		**(235)**		(125)
Investments subject to significant influence		**(216)**		(181)
Regulatory assets		**(196)**		(310)
Other		**(312)**		(322)
Total deferred income tax liabilities	$	**(4,182)**	$	(3,919)
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets	$	**208**	$	237
Long-term deferred income tax liabilities		**(2,352)**		(2,196)
Net deferred income tax liabilities	$	**(2,144)**	$	(1,959)

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 long-term debt and investments. A valuation allowance of $363 million has been recorded as at December 31, 2023 (2022 – $312 million) related to the loss carryforwards, long-term debt and investments.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, as at December 31, 2023, $4.7 billion (2022 – $3.8 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 NOL, capital loss and tax credit carryforwards and their expiration periods as at December 31, 2023 consisted of the following:

millions of dollars	Tax Carryforwards	Subject to Valuation Allowance	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 2,914	$ (1,164)	$ 1,750	2026 - 2043
Capital loss	73	(73)	-	Indefinite
United States				
Federal NOL	$ 1,360	$ (1)	$ 1,359	2036 - Indefinite
State NOL	1,003	(1)	1,002	2026 - Indefinite
Tax credit	454	(3)	451	2025 - 2043
Other				
NOL	$ 81	$ (28)	$ 53	2024 - 2030

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

millions of dollars	**2023**	2022
Balance, January 1	**$ 33**	$ 28
Increases due to tax positions related to current year	**5**	5
Increases due to tax positions related to a prior year	**1**	2
Decreases due to tax positions related to a prior year	**(2)**	(2)
Balance, December 31	**$ 37**	$ 33

Unrecognized tax benefits relate to the timing of certain tax deductions at NSPI and research and development tax credits primarily at TEC. The total amount of unrecognized tax benefits as at December 31, 2023 was $37 million (2022 – $33 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $9 million (2022 – $7 million) with $2 million interest expense recognized in the Consolidated Statements of Income (2022 – $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.

During 2022, the CRA issued notices of reassessment to NSPI for the 2013 through 2016 taxation years. NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 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 $126 million (2022 – $126 million), including interest. NSPI has prepaid $55 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 of the 2006 through 2010 taxation years. 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 difference, if any, either owed to, or refunded from, the 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 Notice of Appeal process is not determinable at this time.

Emera files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, and St. Lucia income tax returns. As at December 31, 2023, 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.

	2023		2022	
Issued and outstanding:	**millions of shares**	**millions of dollars**	millions of shares	millions of dollars
Balance, January 1	**269.95**	**$ 7,762**	261.07	$ 7,242
Issuance of common stock under ATM program (1)(2)	**8.29**	**397**	4.07	248
Issued under the DRIP, net of discounts	**5.26**	**272**	4.21	238
Senior management stock options exercised and Employee Share Purchase Plan	**0.62**	**31**	0.60	34
Balance, December 31	**284.12**	**$ 8,462**	269.95	$ 7,762

(1) For the year ended December 31, 2022, a total of 4,072,469 common shares were issued under Emera's ATM program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs).
(2) For the year ended December 31, 2023, a total of 8,287,037 common shares were issued under Emera's ATM program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs).

As at December 31, 2023, the following common shares were reserved for issuance: 6 million (2022 – 6 million) under the senior management stock option plan, 2 million (2022 – 2.7 million) under the employee common share purchase plan and 18 million (2022 – 10 million) under the 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, 2023, Emera was in compliance with this requirement.

ATM Equity Program

On October 3, 2023, Emera filed a short form base shelf prospectus, primarily in support of the renewal of its ATM Program in Q4 2023 that will allow 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. This ATM Program is expected to remain in effect until November 4, 2025.

12. EARNINGS PER SHARE

Basic earnings per share is determined by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares 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 DRIP.

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

For the millions of dollars (except per share amounts)		Year ended December 31 **2023**		2022
Numerator				
Net income attributable to common shareholders	**$**	**977.7**	$	945.1
Diluted numerator		**977.7**		945.1
Denominator				
Weighted average shares of common stock outstanding – basic		**273.6**		265.5
Stock-based compensation		**0.2**		0.4
Weighted average shares of common stock outstanding – diluted		**273.8**		265.9
Earnings per common share				
Basic	**$**	**3.57**	$	3.56
Diluted	**$**	**3.57**	$	3.55

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of AOCI are as follows:

millions of dollars		Unrealized (loss) gain on translation of self-sustaining foreign operations		Net change in net investment hedges		Losses 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, 2023												
Balance, January 1, 2023	**$**	**639**	**$**	**(62)**	**$**	**16**	**$**	**(2)**	**$**	**(13)**	**$**	**578**
Other comprehensive (loss) income before reclassifications		**(270)**		**38**		**-**		**-**		**-**		**(232)**
Amounts reclassified from AOCI		**-**		**-**		**(2)**		**-**		**(39)**		**(41)**
Net current period other comprehensive (loss) income		**(270)**		**38**		**(2)**		**-**		**(39)**		**(273)**
Balance, December 31, 2023	**$**	**369**	**$**	**(24)**	**$**	**14**	**$**	**(2)**	**$**	**(52)**	**$**	**305**
For the year ended December 31, 2022												
Balance, January 1, 2022	$	10	$	35	$	18	$	(1)	$	(37)	$	25
Other comprehensive income (loss) before reclassifications		629		(97)		-		(1)		-		531
Amounts reclassified from AOCI		-		-		(2)		-		24		22
Net current period other comprehensive income (loss)		629		(97)		(2)		(1)		24		553
Balance, December 31, 2022	$	639	$	(62)	$	16	$	(2)	$	(13)	$	578

The reclassifications out of AOCI are as follows:

For the millions of dollars	Affected line item in the Consolidated Financial Statements	Year ended December 31 2023	2022
Gains on derivatives recognized as cash flow hedges			
Interest rate hedge	Interest expense, net	**$ (2)**	$ (2)
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses	Other income, net	**$ -**	$ 10
Past service costs	Other income, net	**2**	-
Amounts reclassified into obligations	Pension and post-retirement benefits	**(40)**	15
Total before tax		**(38)**	25
Income tax expense		**(1)**	(1)
Total net of tax		**$ (39)**	$ 24
Total reclassifications out of AOCI, net of tax, for the period		**$ (41)**	$ 22

14. INVENTORY

As at millions of dollars	December 31 2023	December 31 2022
Fuel	**$ 382**	$ 404
Materials	**408**	365
Total	**$ 790**	$ 769

15. DERIVATIVE INSTRUMENTS

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

	Derivative Assets		Derivative Liabilities	
As at millions of dollars	**December 31 2023**	December 31 2022	**December 31 2023**	December 31 2022
Regulatory deferral:				
Commodity swaps and forwards	**$ 16**	$ 186	**$ 76**	$ 42
FX forwards	**3**	18	**3**	1
Physical natural gas purchases and sales	**-**	52	**-**	-
	19	256	**79**	43
HFT derivatives:				
Power swaps and physical contracts	**29**	89	**36**	77
Natural gas swaps, futures, forwards, physical contracts	**319**	340	**531**	1,224
	348	429	**567**	1,301
Other derivatives:				
Equity derivatives	**4**	-	**-**	5
FX forwards	**18**	5	**7**	23
	22	5	**7**	28
Total gross current derivatives	**389**	690	**653**	1,372
Impact of master netting agreements:				
Regulatory deferral	**(3)**	(18)	**(3)**	(18)
HFT derivatives	**(146)**	(276)	**(146)**	(276)
Total impact of master netting agreements	**(149)**	(294)	**(149)**	(294)
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078
Current (1)	**174**	296	**386**	888
Long-term (1)	**66**	100	**118**	190
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078

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

Cash Flow Hedges

On May 26, 2021, a treasury lock was settled for a gain of $19 million that is being amortized through interest expense over 10 years as the underlying hedged item settles.

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

For the millions of dollars	Year ended December 31 **2023** **Interest rate hedge**	 2022 Interest rate hedge
Realized gain in interest expense, net	**$ 2**	$ 2
Total gains in net income	**$ 2**	$ 2

As at millions of dollars	**December 31 2023** **Interest rate hedge**	December 31 2022 Interest rate hedge
Total unrealized gain in AOCI – effective portion, net of tax	**$ 14**	$ 16

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 with respect to derivatives receiving regulatory deferral:

millions of dollars	**Physical natural gas purchases**	**Commodity swaps and forwards**	**FX forwards**	Physical natural gas purchases	Commodity swaps and forwards	FX forwards
For the year ended December 31			**2023**			2022
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (109)**	**$ (3)**	$ -	$ (69)	$ 1
Unrealized gain (loss) in regulatory liabilities	**(3)**	**(73)**	**-**	28	343	16
Realized (gain) loss in regulatory assets	**-**	**(5)**	**-**	-	48	-
Realized (gain) loss in regulatory liabilities	**-**	**2**	**-**	-	(41)	-
Realized (gain) loss in inventory (1)	**-**	**4**	**(10)**	-	(121)	1
Realized (gain) in regulated fuel for generation and purchased power (2)	**(49)**	**(9)**	**(4)**	(64)	(146)	-
Other	**-**	**(14)**	**-**	-	-	-
Total change in derivative instruments	**$ (52)**	**$ (204)**	**$ (17)**	$ (36)	$ 14	$ 18

(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.

As at December 31, 2023, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions		2024		2025-2026
Physical natural gas purchases:				
Natural gas (MMBtu)		7		6
Commodity swaps and forwards purchases:				
Natural gas (MMBtu)		16		10
Power (MWh)		1		1
Coal (metric tonnes)		1		-
FX swaps and forwards:				
FX contracts (millions of USD)	$	241	$	70
Weighted average rate		1.3155		1.3197
% of USD requirements		63%		17%

HFT Derivatives

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

For the millions of dollars		Year ended December 31 **2023**		2022
Power swaps and physical contracts in non-regulated operating revenues	**$**	**(6)**	$	17
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues		**1,043**		47
Total gains in net income	**$**	**1,037**	$	64

As at December 31, 2023, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2024	2025	2026	2027	2028 and thereafter
Natural gas purchases (Mmbtu)	296	80	50	38	30
Natural gas sales (Mmbtu)	338	86	16	6	4
Power purchases (MWh)	1	-	-	-	-
Power sales (MWh)	1	-	-	-	-

Other Derivatives

As at December 31, 2023, the Company had equity derivatives in place to manage the cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and FX forwards in place to manage cash flow risk associated with forecasted USD cash inflows. The equity derivatives hedge the return on 2.9 million shares and extends until December 2024. The FX forwards have a combined notional amount of $508 million USD and expire in 2023, 2024 and 2025.

For the millions of dollars				**2023**		Year ended December 31		2022
		FX Forwards		**Equity Derivatives**		FX Forwards		Equity Derivatives
Unrealized gain (loss) in OM&G	**$**	**-**	**$**	**4**	$	-	$	(5)
Unrealized gain (loss) in other income, net		**28**		**-**		(18)		-
Realized loss in OM&G		**-**		**(13)**		-		(17)
Realized loss in other income, net		**(11)**		**-**		(6)		-
Total gains (losses) in net income	**$**	**17**	**$**	**(9)**	$	(24)	$	(22)

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, 2023, the maximum exposure the Company had to credit risk was $1.2 billion (2022 – $1.9 billion), which included 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, FX 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, 2023 was $310 million (2022 – $386 million), which mitigated 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, North American Energy Standards Board agreements and, or Edison Electric Institute agreements. The Company believes entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2023, the Company had $142 million (2022 – $131 million) in financial assets, considered to be past due, which have been outstanding for an average 64 days. The FV of these financial assets was $127 million (2022 – $114 million), the difference of which was 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, 2023		December 31, 2022	
	millions of dollars	**% of total exposure**	millions of dollars	% of total exposure
Receivables, net				
Regulated utilities:				
Residential	**$ 476**	**31%**	$ 455	19%
Commercial	**194**	**13%**	192	8%
Industrial	**84**	**5%**	121	5%
Other	**103**	**7%**	122	5%
Cash collateral	**94**	**6%**	-	0%
	951	**62%**	890	37%
Trading group:				
Credit rating of A- or above	**47**	**3%**	125	5%
Credit rating of BBB- to BBB+	**33**	**2%**	75	3%
Not rated	**108**	**7%**	307	13%
	188	**12%**	507	21%
Other accounts receivable	**151**	**10%**	585	25%
	1,290	**84%**	1,982	83%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**138**	**9%**	202	9%
Credit rating of BBB- to BBB+	**7**	**1%**	8	0%
Not rated	**95**	**6%**	186	8%
	240	**16%**	396	17%
	$ 1,530	**100%**	$ 2,378	100%

Cash Collateral

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

As at millions of dollars	**December 31 2023**	December 31 2022
Cash collateral provided to others	**$ 101**	$ 224
Cash collateral received from others	**$ 22**	$ 112

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, 2023, the total FV of derivatives in a liability position was $504 million (December 31, 2022 – $1,078 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. FV MEASUREMENTS

The Company is required to determine the FV 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 FV 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 FV measurement.

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

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2023 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 7	$ 6	$ -	$ 13
FX forwards	-	3	-	3
	7	9	-	16
HFT derivatives:				
Power swaps and physical contracts	(5)	23	-	18
Natural gas swaps, futures, forwards, physical contracts and related transportation	42	108	34	184
	37	131	34	202
Other derivatives:				
FX forwards	-	18	-	18
Equity derivatives	4	-	-	4
	4	18	-	22
Total assets	48	158	34	240
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	43	30	-	73
FX forwards	-	3	-	3
	43	33	-	76
HFT derivatives:				
Power swaps and physical contracts	-	24	-	24
Natural gas swaps, futures, forwards and physical contracts	13	19	365	397
	13	43	365	421
Other derivatives:				
FX forwards	-	7	-	7
	-	7	-	7
Total liabilities	56	83	365	504
Net assets (liabilities)	$ (8)	$ 75	$ (331)	$ (264)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2022 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 120	$ 48	$ -	$ 168
FX forwards	-	18	-	18
Physical natural gas purchases and sales	-	-	52	52
	120	66	52	238
HFT derivatives:				
Power swaps and physical contracts	9	31	4	44
Natural gas swaps, futures, forwards, physical contracts and related transportation	3	72	34	109
	12	103	38	153
Other derivatives:				
FX forwards	-	5	-	5
Total assets	132	174	90	396
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	15	9	-	24
FX forwards	-	1	-	1
	15	10	-	25
HFT derivatives:				
Power swaps and physical contracts	2	28	1	31
Natural gas swaps, futures, forwards and physical contracts	51	118	825	994
	53	146	826	1,025
Other derivatives:				
FX forwards	-	23	-	23
Equity derivatives	5	-	-	5
Total liabilities	73	179	826	1,078
Net assets (liabilities)	$ 59	$ (5)	$ (736)	$ (682)

The change in the FV of the Level 3 financial assets for the year ended December 31, 2023 was as follows:

	Regulatory Deferral	***HFT Derivatives***		
millions of dollars	**Physical natural gas purchases**	**Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 52**	**$ 4**	**$ 34**	**$ 90**
Realized gains (losses) included in fuel for generation and purchased power	**(49)**	**-**	**-**	**(49)**
Unrealized gains (losses) included in regulatory assets and liabilities	**(3)**	**-**	**-**	**(3)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(4)**	**-**	**(4)**
Balance, December 31, 2023	**$ -**	**$ -**	**$ 34**	**$ 34**

The change in the FV of the Level 3 financial liabilities for the year ended December 31, 2023 was as follows:

	HFT Derivatives		
millions of dollars	**Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 1**	**$ 825**	**$ 826**
Total realized and unrealized gains included in non-regulated operating revenues	**(1)**	**(460)**	**(461)**
Balance, December 31, 2023	**$ -**	**$ 365**	**$ 365**

Significant unobservable inputs used in the FV measurement of Emera's natural gas and power derivatives include third-party sourced pricing for instruments based on illiquid markets. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) FV measurement. Other unobservable inputs used include 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.

The Company uses a modelled pricing valuation technique for determining the FV of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the FV measurements categorized within Level 3 of the FV hierarchy:

millions of dollars	FV		Significant Unobservable Input	Low	High	Weighted average (1)
	Assets	**Liabilities**				
As at December 31, 2023						
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**34**	**365**	Third-party pricing	$1.27	$16.25	$4.85
Total	**$ 34**	**$ 365**				
Net liability		**$ 331**				
As at December 31, 2022						
Regulatory deferral – Physical natural gas purchases	$ 52	$ -	Third-party pricing	$5.79	$31.85	$12.27
HFT derivatives – Power swaps and physical contracts	4	1	Third-party pricing	$43.24	$269.10	$138.79
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	34	825	Third-party pricing	$2.45	$33.88	$12.01
Total	$ 90	$ 826				
Net liability		$ 736				

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

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

As at millions of dollars	Carrying Amount	FV	Level 1	Level 2	Level 3	Total
December 31, 2023	**$ 18,365**	**$ 16,621**	**$ -**	**$ 16,363**	**$ 258**	**$ 16,621**
December 31, 2022	$ 16,318	$ 14,670	$ -	$ 14,284	$ 386	$ 14,670

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, 2023, the FV of the Hybrid Notes was $1.2 billion (2022 – $1.1 billion). An after-tax foreign currency gain of $38 million was recorded in AOCI for the year ended December 31, 2023 (2022 – $97 million after-tax loss).

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 $163 million for the year ended December 31, 2023 (2022 – $157 million). NSPML is accounted for as an equity investment, and therefore 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 $14 million for the year ended December 31, 2023 (2022 – $9 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, 2023 and at December 31, 2022.

18. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars		**December 31 2023**		December 31 2022
Customer accounts receivable – billed	**$**	**805**	$	1,096
Capitalized transportation capacity (1)		**358**		781
Customer accounts receivable – unbilled		**363**		424
Prepaid expenses		**105**		82
Income tax receivable		**10**		9
Allowance for credit losses		**(15)**		(17)
NMGC gas hedge settlement receivable (2)		**-**		162
Other		**191**		360
Total receivables and other current assets	**$**	**1,817**	$	2,897

(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.
(2) Offsetting amount is included in regulatory liabilities for NMGC as gas hedges are part of the PGAC. For more information, refer to note 6.

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 62 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain they will be exercised.

As at millions of dollars	Classification	**December 31 2023**	December 31 2022
Right-of-use asset	Other long-term assets	**$ 54**	$ 58
Lease liabilities			
Current	Other current liabilities	**3**	3
Long-term	Other long-term liabilities	**55**	59
Total lease liabilities		**$ 58**	$ 62

The Company recorded lease expense of $127 million for the year ended December 31, 2023 (2022 – $138 million), of which $119 million (2022 – $131 million) related 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 dollars	2024	2025	2026	2027	2028	Thereafter	Total
Minimum lease payments	$ 6	$ 5	$ 3	$ 3	$ 3	$ 111	$ 131
Less imputed interest							(73)
Total							$ 58

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

For the	Year ended December 31 **2023**	2022
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of dollars)	**$ 8**	$ 8
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of dollars)	**$ 1**	$ 1
Weighted average remaining lease term (years)	**44**	44
Weighted average discount rate- operating leases	**3.93%**	3.98%

Lessor

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

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 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.

Commencing in October 2023, the Company leased a RNG facility to a biogas producer that is classified as a sales-type lease. The term of the facility lease is 15 years, with a nominal value purchase at the end of the term and a net investment of approximately $35 million USD.

Commencing in January 2022, the Company leased Seacoast pipeline, a 21-mile, 30-inch lateral that is classified as a sales-type lease. The term of the pipeline lateral lease is 34 years with a net investment of $100 million USD. The lessee of the pipeline lateral has renewal options for an additional 16 years. These renewal options have not been included as part of the pipeline lateral lease term as it is not reasonably certain that they will be exercised.

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

As at millions of dollars		**December 31 2023**		December 31 2022
Total minimum lease payment to be received	**$**	**1,360**	$	1,393
Less: amounts representing estimated executory costs		**(190)**		(205)
Minimum lease payments receivable	**$**	**1,170**	$	1,188
Estimated residual value of leased property (unguaranteed)		**183**		183
Less: Credit loss reserve		**(2)**		-
Less: unearned finance lease income		**(693)**		(733)
Net investment in direct finance and sales-type leases	**$**	**658**	$	638
Principal due within one year (included in "Receivables and other current assets")		**37**		34
Net Investment in direct finance and sales type leases - long-term	**$**	**621**	$	604

As at December 31, 2023, future minimum lease payments to be received for each of the next five years and in aggregate thereafter were as follows:

millions of dollars		2024		2025		2026		2027		2028		Thereafter		Total
Minimum lease payments to be received	$	97	$	99	$	98	$	97	$	96	$	873	$	1,360
Less: executory costs														(190)
Total													$	1,170

20. PROPERTY, PLANT AND EQUIPMENT

PP&E consisted of the following regulated and non-regulated assets:

As at millions of dollars	Estimated useful life		**December 31 2023**		December 31 2022
Generation	3 to 131	**$**	**13,500**	$	13,083
Transmission	10 to 80		**2,835**		2,731
Distribution	4 to 80		**7,417**		6,978
Gas transmission and distribution	6 to 92		**5,536**		5,061
General plant and other (1)	2 to 71		**2,985**		2,723
Total cost			**32,273**		30,576
Less: Accumulated depreciation (1)			**(9,994)**		(9,574)
			22,279		21,002
Construction work in progress (1)			**2,097**		1,994
Net book value		**$**	**24,376**	$	22,996

(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, 2023, SeaCoast’s share of plant in service was $27 million USD (2022 – $27 million USD), and accumulated depreciation of $2 million USD (2022 – $1 million USD). 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 (“DB”) and defined-contribution (“DC”) 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, and Grand Bahama Island.

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 dollars			Year ended December 31	
	2023		2022	
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	**$ 2,158**	**$ 243**	$ 2,624	$ 318
Service cost	**30**	**3**	41	4
Plan participant contributions	**6**	**6**	6	6
Interest cost	**111**	**13**	80	9
Plan amendments	**-**	**(14)**	-	-
Benefits paid	**(147)**	**(29)**	(174)	(31)
Actuarial losses (gains)	**146**	**10**	(480)	(79)
Settlements and curtailments	**(8)**	**-**	(6)	-
FX translation adjustment	**(23)**	**(5)**	67	16
Balance, December 31	**$ 2,273**	**$ 227**	$ 2,158	$ 243
Change in plan assets				
Balance, January 1	**$ 2,163**	**$ 46**	$ 2,702	$ 51
Employer contributions	**42**	**23**	45	24
Plan participant contributions	**6**	**6**	6	6
Benefits paid	**(147)**	**(29)**	(174)	(31)
Actual return on assets, net of expenses	**262**	**3**	(489)	(7)
Settlements and curtailments	**(8)**	**-**	(6)	-
FX translation adjustment	**(20)**	**(1)**	79	3
Balance, December 31	**$ 2,298**	**$ 48**	$ 2,163	$ 46
Funded status, end of year	**$ 25**	**$ (179)**	$ 5	$ (197)

The actuarial losses recognized in the period are primarily due to changes in the discount rate, higher than expected indexation, and compensation-related assumption changes.

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) exceeded the plan assets for the years ended December 31 was as follows:

millions of dollars	**2023**		2022	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 120**	**$ 205**	$ 1,006	$ 221
FV of plan assets	**37**	**-**	914	-
Funded status	**$ (83)**	**$ (205)**	$ (92)	$ (221)

Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets:
The ABO for the DB pension plans was $2,172 million as at December 31, 2023 (2022 – $2,080 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 was as follows:

millions of dollars	**2023**	2022
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 114**	$ 111
FV of plan assets	**37**	33
Funded status	**$ (77)**	$ (78)

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

As at millions of dollars		December 31 2023		December 31 2022
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	**$ (5)**	**$ (18)**	$ (13)	$ (20)
Long-term liabilities	**(78)**	**(187)**	(80)	(201)
Other long-term assets	**108**	**26**	98	24
AOCI, net of tax and regulatory assets	**385**	**20**	358	22
Less: Deferred income tax (expense) recovery in AOCI	**(8)**	**(1)**	(7)	(1)
Net amount recognized	**$ 402**	**$ (160)**	$ 356	$ (176)

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 dollars	Regulatory assets	Actuarial (gains) losses	Past service (gains) costs
Defined Benefit Pension Plans			
Balance, January 1, 2023	$ 336	$ 15	$ -
Amortized in current period	(6)	(3)	-
Current year additions	1	41	-
Change in FX rate	(7)	-	-
Balance, December 31, 2023	$ 324	$ 53	$ -
Non-pension benefits plans			
Balance, January 1, 2023	$ 31	$ (10)	$ -
Amortized in current period	2	3	-
Current year reductions	(3)	(1)	(3)
Change in FX rate	(1)	-	1
Balance, December 31, 2023	$ 29	$ (8)	$ (2)

As at millions of dollars		December 2023		December 2022
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	**$ 53**	**(8)**	$ 15	$ (10)
Past service gains	**-**	**(2)**	-	-
Deferred income tax expense	**8**	**1**	7	1
AOCI, net of tax	**61**	**(9)**	22	(9)
Regulatory assets	**324**	**29**	336	31
AOCI, net of tax and regulatory assets	**$ 385**	**$ 20**	$ 358	$ 22

Benefit Cost Components:
Emera's net periodic benefit cost included the following:

As at millions of dollars		2023		Year ended December 31 2022
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 30**	**$ 3**	$ 41	$ 4
Interest cost	**111**	**13**	80	9
Expected return on plan assets	**(161)**	**(2)**	(144)	-
Current year amortization of:				
Actuarial losses (gains)	**1**	**(3)**	8	-
Regulatory assets (liability)	**6**	**(2)**	21	2
Settlement, curtailments	**2**	**-**	2	-
Total	**$ (11)**	**$ 9**	$ 8	$ 15

The expected return on plan assets is determined based on the market-related value of plan assets of $2,577 million as at January 1, 2023 (2022 – $2,482 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	10%
Fixed income	34%	to	49%
Equities:			
Canadian	7%	to	17%
Non-Canadian	35%	to	59%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average		
Cash and cash equivalents	0%	to	10%
Fixed income	29%	to	49%
Equities	48%	to	68%

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 FV its investments:

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
As at					December 31, 2023
Cash and cash equivalents	$ -	$ 40	$ -	$ 40	2 %
Net in-transits	-	(9)	-	(9)	- %
Equity securities:					
Canadian equity	-	96	-	96	4 %
United States equity	-	141	-	141	6 %
Other equity	-	112	-	112	5 %
Fixed income securities:					
Government	-	-	172	172	8 %
Corporate	-	-	90	90	4 %
Other	-	4	5	9	- %
Mutual funds	-	50	-	50	2 %
Other	-	6	(1)	5	- %
Open-ended investments measured at NAV (1)	1,006	-	-	1,006	44 %
Common collective trusts measured at NAV (2)	586	-	-	586	25 %
Total	$ 1,592	$ 440	$ 266	$ 2,298	100 %
As at					December 31, 2022
Cash and cash equivalents	$ -	$ 70	$ -	$ 70	3 %
Net in-transits	-	(70)	-	(70)	(3)%
Equity securities:					
Canadian equity	-	87	-	87	4 %
United States equity	-	233	-	233	11 %
Other equity	-	186	-	186	8 %
Fixed income securities:					
Government	-	-	104	104	5 %
Corporate	-	-	83	83	4 %
Other	-	3	11	14	1 %
Mutual funds	-	68	-	68	3 %
Other	-	-	(3)	(3)	- %
Open-ended investments measured at NAV (1)	790	-	-	790	36 %
Common collective trusts measured at NAV (2)	601	-	-	601	28 %
Total	$ 1,391	$ 577	$ 195	$ 2,163	100 %

(1) Net asset value ("NAV") investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated at least monthly and the funds honour 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 honour subscription and redemption activity regularly.

Refer to note 16 for more information on the FV hierarchy and inputs used to measure FV.

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 exception to this is the NMGC Retiree Medical Plan, which is fully funded.

Investments in Emera:
As at December 31, 2023 and 2022, assets related to the pension funds and post-retirement benefit plans did 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 expected cash flows for DB pension and other post-retirement benefit plans:

millions of dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2024	$ 34	$ 19
Expected benefit payments		
2024	172	21
2025	163	21
2026	166	21
2027	171	21
2028	173	20
2029 – 2033	890	95

Assumptions:
The following table shows the assumptions that have been used in accounting for DB pension and other post-retirement benefit plans:

	2023		2022	
(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	**4.89 %**	**4.89 %**	5.33 %	5.31 %
Discount rate - future service	**4.88 %**	**4.89 %**	5.34 %	5.32 %
Rate of compensation increase	**3.87 %**	**3.85 %**	3.62 %	3.61 %
Health care trend - initial (next year)	**-**	**6.04 %**	-	5.40 %
- ultimate	**-**	**3.76 %**	-	3.77 %
- year ultimate reached		**2043**		2043
Benefit cost for year ended December 31:				
Discount rate - past service	**5.33 %**	**5.31 %**	3.05 %	2.81 %
Discount rate - future service	**5.34 %**	**5.32 %**	3.18 %	2.92 %
Expected long-term return on plan assets	**6.56 %**	**2.16 %**	6.07 %	1.32 %
Rate of compensation increase	**3.62 %**	**3.61 %**	3.31 %	3.29 %
Health care trend - initial (current year)	**-**	**5.40 %**	-	5.09 %
- ultimate	**-**	**3.77 %**	-	3.77 %
- year ultimate reached		**2043**		2042

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 DC pension plan for certain employees. The Company's contribution for the year ended December 31, 2023 was $45 million (2022 – $41 million).

22. GOODWILL

The change in goodwill for the year ended December 31 was due to the following:

millions of dollars		2023		2022
Balance, January 1	$	6,012	$	5,696
Change in FX rate		(141)		389
GBPC impairment charge		-		(73)
Balance, December 31	$	5,871	$	6,012

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, 2023, primarily related to TECO Energy (reporting units with goodwill are TEC, PGS, and NMGC).

In 2023, Emera performed qualitative impairment assessments for NMGC and PGS, concluding that the FV of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessments were performed and no impairment charges were recognized. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income approach and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result no impairment charges were recognized.

In 2022, the Company elected to bypass a qualitative assessment and performed a quantitative impairment assessment for GBPC, using the income approach. It was determined that the FV did not exceed its carrying amount, including goodwill. As a result of this assessment, a goodwill impairment charge of $73 million was recorded in 2022, reducing the GBPC goodwill balance to nil as at December 31, 2022. This non-cash charge is included in "GBPC impairment charge" on the Consolidated Statements of Income.

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 dollars		2023	Weighted average interest rate		2022	Weighted average interest rate
TEC						
Advances on revolving credit facilities	$	277	5.68 %	$	1,380	5.00 %
Emera						
Non-revolving term facilities		796	6.07 %		796	5.19 %
Bank indebtedness		9	- %		-	- %
TECO Finance						
Advances on revolving credit and term facilities		245	6.54 %		481	5.47 %
PGS						
Advances on revolving credit facilities		73	6.36 %		-	- %
NMGC						
Advances on revolving credit facilities		25	6.46 %		59	5.15 %
GBPC						
Advances on revolving credit facilities		8	5.54 %		10	5.25 %
Short-term debt	$	1,433		$	2,726	

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 dollars	Maturity		2023		2022
TEC - Unsecured committed revolving credit facility	2026	$	**401**	$	1,084
TECO Energy/TECO Finance - revolving credit facility	2026		**-**		542
TECO Finance - Unsecured committed revolving credit facility	2026		**529**		-
Emera - Unsecured non-revolving term facility	2024		**400**		400
Emera - Unsecured non-revolving term facility	2024		**400**		400
PGS - Unsecured revolving credit facility	2028		**331**		-
TEC - Unsecured revolving facility	2024		**265**		542
TEC - Unsecured revolving facility	2024		**265**		-
NMGC - Unsecured revolving credit facility	2026		**165**		169
Other - Unsecured committed revolving credit facilities	Various		**17**		18
Total		$	**2,773**	$	3,155
Less:					
Advances under revolving credit and term facilities			**1,433**		2,731
Letters of credit issued within the credit facilities			**3**		4
Total advances under available facilities			**1,436**		2,735
Available capacity under existing agreements		$	**1,337**	$	420

The weighted average interest rate on outstanding short-term debt at December 31, 2023 was 5.95 per cent (2022 – 5.01 per cent).

Recent Significant Financing Activity by Segment

Florida Electric Utilities

On November 24, 2023, TEC repaid its $400 million USD unsecured non-revolving facility, which expired on December 13, 2023.

On April 3, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on April 1, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term secured overnight financing rate ("SOFR"), Wells Fargo's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

On March 1, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on February 28, 2024. The credit facility contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term SOFR, the Bank of Nova Scotia's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

Gas Utilities and Infrastructure

On December 1, 2023, PGS entered into a $250 million USD senior unsecured revolving credit facility with a group of banks, maturing on December 1, 2028. PGS has the ability to request the lenders to increase their commitments under the credit facility by up to $100 million USD in the aggregate subject to agreement from participating lenders. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin.

Other

On December 16, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from December 16, 2023 to December 16, 2024. There were no other changes in commercial terms from the prior agreement.

On June 30, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from August 2, 2023 to August 2, 2024. There were no other changes in commercial terms from the prior agreement.

24. OTHER CURRENT LIABILITIES

As at millions of dollars	**December 31 2023**	December 31 2022
Accrued charges	**$ 172**	$ 174
Nova Scotia Cap-and-Trade Program provision (note 6)	**-**	172
Accrued interest on long-term debt	**107**	97
Pension and post-retirement liabilities (note 21)	**23**	33
Sales and other taxes payable	**11**	14
Income tax payable	**2**	9
Other	**112**	80
	$ 427	$ 579

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 dollars	Weighted average interest rate (1) 2023	2022	Maturity		2023		2022
Emera							
Bankers acceptances, SOFR loans	Variable	Variable	2027	**$**	**465**	$	403
Unsecured fixed rate notes	4.84%	2.90%	2030		**500**		500
Fixed to floating subordinated notes (2)	6.75%	6.75%	2076		**1,587**		1,625
				$	**2,552**	$	2,528
Emera Finance							
Unsecured senior notes	3.65%	3.65%	2024 - 2046	**$**	**3,637**	$	3,725
TEC (3)							
Fixed rate notes and bonds	4.61%	4.15%	2024 - 2051	**$**	**5,654**	$	4,341
PGS							
Fixed rate notes and bonds	5.63%	3.78%	2028 - 2053	**$**	**1,223**	$	772
NMGC							
Fixed rate notes and bonds	3.78%	3.11%	2026 - 2051	**$**	**642**	$	521
Non-revolving term facility, floating rate	Variable	Variable	2024		**30**		108
				$	**672**	$	629
NMGI							
Fixed rate notes and bonds	3.64%	3.64%	2024	**$**	**198**	$	203
NSPI							
Discount Notes (4)	Variable	Variable	2024 - 2027	**$**	**721**	$	881
Medium term fixed rate notes	5.13%	5.14%	2025 - 2097		**3,165**		2,665
				$	**3,886**	$	3,546
EBP							
Senior secured credit facility	Variable	Variable	2026	**$**	**246**	$	249
ECI							
Secured senior notes	Variable	Variable	2027	**$**	**75**	$	86
Amortizing fixed rate notes	4.00%	3.97%	2026		**79**		100
Non-revolving term facility, floating rate	Variable	Variable	2025		**29**		30
Non-revolving term facility, fixed rate	2.15%	2.05%	2025 - 2027		**155**		91
Secured fixed rate senior notes (5)	3.09%	3.06%	2024 - 2029		**84**		142
				$	**422**	$	449
Adjustments							
Fair market value adjustment - TECO Energy acquisition				**$**	**-**	$	2
Debt issuance costs					**(125)**		(126)
Amount due within one year					**(676)**		(574)
				$	**(801)**	$	(698)
Long-Term Debt				**$**	**17,689**	$	15,744

(1) Weighted average interest rate of fixed rate long-term debt.

(2) In 2023, the Company recognized $109 million in interest expense (2022 – $110 million) related to its fixed to floating subordinated notes.

(3) A substantial part of TEC's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under TEC's first mortgage bond indenture.

(4) Discount notes are backed by a revolving credit facility which matures in 2027. Banker's acceptances are issued under NSPI's non-revolving term facility which matures in 2024. NSPI has the intention and unencumbered ability to refinance bankers' acceptances for a period of greater than one year.

(5) Notes are issued and payable in either USD or BBD.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of dollars	Maturity	2023	2022
Emera – revolving credit facility (1)	June 2027	**$ 900**	$ 900
TEC - Unsecured committed revolving credit facility	December 2026	**657**	-
NSPI - revolving credit facility (1)	December 2027	**800**	800
NSPI - non-revolving credit facility	July 2024	**400**	400
Emera - Unsecured non-revolving credit facility	February 2024	**400**	-
NMGC - Unsecured non-revolving credit facility	March 2024	**30**	108
ECI – revolving credit facilities	October 2024	**10**	11
Total		**$ 3,197**	$ 2,219
Less:			
Borrowings under credit facilities		**1,884**	1,396
Letters of credit issued inside credit facilities		**6**	12
Use of available facilities		**$ 1,890**	$ 1,408
Available capacity under existing agreements		**$ 1,307**	$ 811

(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, 2023
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 January 30, 2024, TEC issued $500 million USD of senior unsecured bonds that bear interest at 4.90 per cent with a maturity date of March 1, 2029. Proceeds from the issuance were primarily used for repayment of short-term borrowings outstanding under the 5-year credit facility. Therefore, $497 million USD of short-term borrowings that were repaid was classified as long-term debt at December 31, 2023.

Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053.

Gas Utilities and Infrastructure

On December 19, 2023, PGS completed an issuance of $925 million USD in senior notes. The issuance included $350 million USD senior notes that bear interest at 5.42 per cent with a maturity date of December 19, 2028, $350 million USD senior notes that bear interest at 5.63 per cent with a maturity date of December 19, 2033 and $225 million USD senior notes that bear interest at 5.94 per cent with a maturity date of December 19, 2053.

On October 19, 2023, NMGC issued $100 million USD in senior unsecured notes that bear interest at 6.36 per cent with a maturity date of October 19, 2033.

Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028.

Other

On August 18, 2023, Emera entered into a $400 million non-revolving term facility with a maturity date of February 19, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. On February 16, 2024, Emera extended the term of this agreement to a maturity date of February 19, 2025.

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030.

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 dollars	2024	2025	2026	2027	2028	Thereafter	Total
Emera	$ 199	$ -	$ 1,587	$ 266	$ -	$ 500	$ 2,552
Emera US Finance LP	397	-	992	-	-	2,248	3,637
TEC	397	-	-	-	-	5,257	5,654
PGS	-	-	-	-	463	760	1,223
NMGC	30	-	93	-	-	549	672
NMGI	198	-	-	-	-	-	198
NSPI	398	125	40	323	-	3,000	3,886
EBP	-	-	246	-	-	-	246
ECI	51	139	89	77	62	4	422
Total	$ 1,670	$ 264	$ 3,047	$ 666	$ 525	$ 12,318	$ 18,490

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 FV of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of dollars	**2023**	2022
Balance, January 1	**$ 174**	$ 174
Accretion included in depreciation expense	**9**	9
Change in FX rate	**(1)**	3
Additions	**-**	1
Accretion deferred to regulatory asset (included in PP&E)	**18**	1
Liabilities settled	**(8)**	(1)
Revisions in estimated cash flows	**-**	(13)
Balance, December 31	**$ 192**	$ 174

27. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2023, 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 dollars	2024	2025	2026	2027	2028	Thereafter	Total
Transportation (1)	$ 696	$ 495	$ 405	$ 388	$ 338	$ 2,597	$ 4,919
Purchased power (2)	274	249	263	312	312	3,435	4,845
Fuel, gas supply and storage	556	215	62	-	5	-	838
Capital projects	778	111	70	1	-	-	960
Equity investment commitments (3)	240	-	-	-	-	-	240
Other	154	147	56	46	35	221	659
	$ 2,698	$ 1,217	$ 856	$ 747	$ 690	$ 6,253	$ 12,461

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $134 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) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion. In December 2023, the UARB approved the collection of up to $164 million from NSPI for the recovery of Maritime Link costs in 2024. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Construction of the LIL is complete, and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

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 and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Other" in the above table.

B. Legal Proceedings

Superfund and Former Manufactured Gas Plant Sites

Previously, TEC had been a potentially responsible party ("PRP") for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, Peoples Gas System, Inc. is also now a PRP for those sites (in addition to third party PRPs for certain sites). While the aggregate joint and several liability associated with these sites has not changed as a result of the PGS legal separation, the sites continue to present the potential for significant response costs. As at December 31, 2023, the aggregate financial liability of the Florida utilities is estimated to be $15 million ($11 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 the Florida utilities. The estimates to perform the work are based on the Florida utilities' 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, the Florida utilities could be liable for more than their 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 FV 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 an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee ("ERMC") and monitored by the Board of Directors, to ensure an effective, consistent and coherent approach to risk management. The Board of Directors has a Risk and Sustainability Committee ('RSC") with a mandate that 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.

Regulatory and Political Risk

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

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

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

Emera's utilities generally manage this risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries work to establish collaborative relationships with regulatory stakeholders, including customer representatives, both through its approach to filings and additional efforts with technical conferences and, where appropriate, negotiated settlements.

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

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

Foreign Exchange Risk

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

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

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries do not impact net income as they are reported in 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.

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

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

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

General Economic Risk

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

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

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

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Market Risk".

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

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

Commodity Price Risk

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

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

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

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

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

To measure commodity price risk exposure, Emera Energy employs a number of controls and processes, including an estimated VaR analysis of its exposures. The VaR amount represents an estimate of the potential change in FV 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 income 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, 2023:

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 Investor Services ("Moody's") or S&P Global Ratings ("S&P"). TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

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

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

NSPI has issued guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of $104 million USD (2022 – $119 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $103 million USD (December 31, 2022 – $145 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 2024. The amount committed as at December 31, 2023 was $56 million (December 31, 2022 – $63 million).

Collaborative Arrangements

For the years ended December 31, 2023 and 2022, 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" on the Consolidated Statements of Income. In 2023, NSPI recognized $8 million net expense (2022 – $12 million) in "Regulated fuel for generation and purchased power" and $3 million (2022 – $3 million) in "OM&G" on the Consolidated Statements of Income.

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, 2023		December 31, 2022	
	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	$ 1.6085	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 25.00	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0505	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Series H	$ 1.5810	$ 25.00	**12,000,000**	**$ 295**	12,000,000	$ 295
Series J	$ 1.0625	$ 25.00	**8,000,000**	**$ 196**	8,000,000	$ 196
Series L	$ 1.1500	$ 26.00	**9,000,000**	**$ 222**	9,000,000	$ 222
Total			**58,000,000**	**$ 1,422**	58,000,000	$ 1,422

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 (5)(6)	4.100	1.6085	2.65	August 15, 2028	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 (5)(7)	4.900	1.5810	4.90	August 15, 2028	25.00	Series I
Series J	4.250	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate						
Series E (8)	4.500	1.1250			25.00	
Series L (9)	4.600	1.1500		November 15, 2026	26.00	

(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, 2028, February 15, 2025 and August 15, 2028, 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) On July 6, 2023, Emera announced it would not redeem the outstanding Preferred Shares, Series C and Series H on August 15, 2023. On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C Shares were converted into Series D Shares and no Series H Shares were converted into Series I shares.
(6) The annual fixed dividend per share for Series C Shares was reset from $1.1802 to $1.6085 for the five-year period from and including August 15, 2028.
(7) The annual fixed dividend per share for Series H Shares was reset from $1.2250 to $1.5810 for the five-year period from and including August 15, 2028.
(8) First Preferred Shares, Series E are redeemable at $25.00 per share.
(9) 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 are deducted on the Consolidated Statements of Income before arriving at “Net income attributable to common shareholders” and shown on the Consolidated Statement of Changes in 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 dollars		December 31 2023		December 31 2022
Preferred shares of GBPC	$	14	$	14
	$	14	$	14

Preferred shares of GBPC:

Authorized:
10,000 non-voting cumulative redeemable variable perpetual preferred shares.

	2023			2022		
Issued and outstanding:	number of shares		millions of dollars	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 dollars	Year ended December 31 2023			2022
Changes in non-cash working capital:				
Inventory	$	(31)	$	(214)
Receivables and other current assets (1)		653		(636)
Accounts payable		(538)		423
Other current liabilities (2)		(179)		193
Total non-cash working capital	$	(95)	$	(234)

(1) Includes $162 million related to the January 2023 settlement of NMGC gas hedges (2022 – ($162) million). Offsetting regulatory liability is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
(2) Includes ($166) million related to the Nova Scotia Cap-and-Trade program (2022 – $172 million). For further detail, refer to note 6. Offsetting regulatory asset (FAM) balance is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.

For the millions of dollars	Year ended December 31 2023			2022
Supplemental disclosure of cash paid:				
Interest	$	930	$	699
Income taxes	$	43	$	67
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	$	271	$	237
Decrease in accrued capital expenditures	$	(19)	$	(13)
Reclassification of short-term debt to long-term debt	$	657	$	-
Reclassification of long-term debt to short-term debt	$	-	$	500
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	$	123	$	(157)

31. STOCK-BASED COMPENSATION

Employee Common Share Purchase Plan and Common Shareholders Dividend Reinvestment and Share Purchase Plan

Eligible employees may participate in the ECSPP. As of December 31, 2023, 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 reinvestment of dividends for all participants except where prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares. As at December 31, 2023, Emera was in compliance with this requirement.

Compensation cost for shares issued under the ECSPP for the year ended December 31, 2023 was $3 million (2022 – $3 million) and was included in "OM&G" on the Consolidated Statements of Income.

The Company also has a Common Shareholders DRIP, which provides an opportunity for shareholders residing in Canada 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 2023.

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 price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded before the date on which the option is granted. The maximum aggregate number of shares issuable under this plan is 14.7 million shares. As at December 31, 2023, Emera was in compliance with this requirement.

Stock options granted in 2021 and prior vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. Stock options granted in 2022 and thereafter vest in 20 per cent increments on the first, second, third, fourth and fifth 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.

For stock options granted in 2021 and prior, unless a stock option has expired, vested options may be exercised within the 27 months following the option holder's 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. Commencing with the 2022 stock option grant, vested options may be exercised during the full term of the option 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 FV per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

	2023	2022
Weighted average FV per option	**$ 6.32**	$ 5.35
Expected term (1)	**5 years**	5 years
Risk-free interest rate (2)	**3.53 %**	1.79 %
Expected dividend yield (3)	**5.05 %**	4.55 %
Expected volatility (4)	**20.07 %**	18.87 %

(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 2023:

	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, 2022	2,853,879	$ 50.41	1,348,400	$ 4.08
Granted	483,100	54.64	483,100	6.32
Exercised	(146,475)	43.94	N/A	N/A
Forfeited	(94,900)	56.32	(51,625)	3.61
Vested	N/A	N/A	(526,620)	3.58
Options outstanding December 31, 2023	**3,095,604**	**$ 51.20**	**1,253,255**	**$ 5.17**
Options exercisable December 31, 2023 (2)(3)	**1,842,349**	**$ 48.39**		

(1) As at December 31, 2023, there was $5 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 (2022 – $4 million, 3 years).
(2) As at December 31, 2023, the weighted average remaining term of vested options was 5 years with an aggregate intrinsic value of $8 million (2022 – 5 years, $10 million).
(3) As at December 31, 2023, the FV of options that vested in the year was $ 2 million (2022 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2023 was $2 million (2022 – $2 million), which was included in "OM&G" on the Consolidated Statements of Income.

As at December 31, 2023, cash received from option exercises was $6 million (2022 – $9 million). The total intrinsic value of options exercised for the year ended December 31, 2023 was $2 million (2022 – $4 million). The range of exercise prices for the options outstanding as at December 31, 2023 was $32.35 to $60.03 (2022 – $32.35 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 short-term 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 made in cash.

In addition, special DSU awards may be made from time to time by the Management Resources and Compensation Committee ("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, 2023 is presented in the following table:

	Employee DSU	Weighted Average Grant Date FV	Director DSU	Weighted Average Grant Date FV
Outstanding as at December 31, 2022	627,223	$ 41.55	664,258	$ 45.83
Granted including DRIP	85,740	47.66	117,893	49.99
Exercised	N/A	N/A	(53,093)	49.39
Outstanding and exercisable as at December 31, 2023	**712,963**	**$ 42.29**	**729,058**	**$ 46.24**

Compensation cost recovery recognized for employee and director DSU's for the year ended December 31, 2023 was $2 million (2022 – $6 million). Tax expense related to this compensation cost recovery for share units realized for the year ended December 31, 2023 was $1 million (2022 – $2 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for employees was $36 million (2022 – $33 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for directors was $37 million (2022 – $34 million). Cash payments made during the year ended December 31, 2023 associated with the DSU plan were $3 million (2022 – $8 million).

Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the 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. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee PSUs for the year ended December 31, 2023 is presented in the following table:

	Employee PSU	Weighted Average Grant Date FV	Aggregate intrinsic value
Outstanding as at December 31, 2022	690,446	$ 56.24	$ 40
Granted including DRIP	386,261	52.71	
Exercised	(323,155)	54.62	
Forfeited	(10,187)	55.15	
Outstanding as at December 31, 2023	**743,365**	**$ 55.13**	**$ 41**

Compensation cost recognized for the PSU plan for the year ended December 31, 2023 was $11 million (2022 – $18 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $5 million). Cash payments made during the year ended December 31, 2023 associated with the PSU plan were $19 million (2022 – $24 million).

Restricted Share Unit Plan

Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the 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. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee RSUs for the year ended December 31, 2023 is presented in the following table:

	Employee RSU	Weighted Average Grant Date FV	Aggregate intrinsic value
Outstanding as at December 31, 2022	508,468	$ 56.25	$ 30
Granted including DRIP	236,537	52.07	
Exercised	(171,537)	54.62	
Forfeited	(10,827)	54.76	
Outstanding as at December 31, 2023	**562,641**	**$ 55.01**	**$ 32**

Compensation cost recognized for the RSU plan for the year ended December 31, 2023 was $10 million (2022 – $9 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $2 million). Cash payments made during the year ended December 31, 2023 associated with the RSU plan were $10 million (2022– 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 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, 2023**		December 31, 2022	
millions of dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 489**	**$ 6**	$ 501	$ 6

33. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 26, 2024, the date the financial statements were issued.

Exhibit 99.4

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our Firm under the caption "Experts" in the Annual Information Form and to the use in this Annual Report on Form 40-F of our report dated February 26, 2024, with respect to the consolidated balance sheets of Emera Incorporated as at December 31, 2023 and 2022, 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, included in this Annual Report on Form 40-F.

/s/ Ernst & Young LLP
Chartered Professional Accountants

Halifax, Canada
February 26, 2024

Exhibit 99.5

CERTIFICATION

I, Scott C. Balfour, certify that:

1. I have reviewed this annual report on Form 40-F of Emera Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer' s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer' s internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer' s internal control over financial reporting; and

5. The issuer' s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer' s auditors and the audit committee of the issuer' s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer' s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer' s internal control over financial reporting.

Date: February 26, 2024

/s/ Scott C. Balfour

Scott C. Balfour
President & Chief Executive Officer

Exhibit 99.6

CERTIFICATION

I, Gregory W. Blunden, certify that:

1. I have reviewed this annual report on Form 40-F of Emera Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer' s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer' s internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer' s internal control over financial reporting; and

5. The issuer' s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer' s auditors and the audit committee of the issuer' s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer' s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer' s internal control over financial reporting.

Date: February 26, 2024

/s/ Gregory W. Blunden

Gregory W. Blunden
Chief Financial Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Emera Incorporated (the "Company") on Form 40-F for the year ended December 31, 2023 (the "Report"), as filed with the U.S. Securities and Exchange Commission,

I, Scott C. Balfour, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as enacted pursuant to Section 906 of the U.S. Sarbanes-Oxley Act of 2002, that to my knowledge:

(i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the U.S. Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2024

/s/ Scott C. Balfour

Scott C. Balfour
President & Chief Executive Officer

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Emera Incorporated (the "Company") on Form 40-F for the year ended December 31, 2023 (the "Report"), as filed with the U.S. Securities and Exchange Commission,

I, Gregory W. Blunden, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as enacted pursuant to Section 906 of the U.S. Sarbanes-Oxley Act of 2002, that to my knowledge:

(i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the U.S. Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2024

/s/ Gregory W. Blunden
Gregory W. Blunden
Chief Financial Officer

Cover Page	12 Months Ended Dec. 31, 2023 shares
Cover [Abstract]	
Entity Central Index Key	0001127248
Document Type	40-F
Document Registration Statement	false
Document Annual Report	true
Amendment Flag	false
Document Period End Date	Dec. 31, 2023
Document Fiscal Period Focus	FY
Document Fiscal Year Focus	2023
Current Fiscal Year End Date	--12-31
Entity File Number	000-54516
Entity Registrant Name	EMERA INCORPORATED
Entity Incorporation, State or Country Code	A5
Entity Listings [Line Items]	
Entity Address, Address Line One	5151 Terminal Road
Entity Address, City or Town	Halifax
Entity Address, State or Province	NS
Entity Address, Country	CA
Entity Address, Postal Zip Code	B3J 1A1
City Area Code	902
Local Phone Number	428-6096
Annual Information Form	true
Audited Annual Financial Statements	true
Document Fin Stmt Error Correction Flag	false
Entity Current Reporting Status	No
Entity Interactive Data Current	Yes
Entity Emerging Growth Company	false
ICFR Auditor	false
Auditor Name	Ernst & Young LLP
Auditor Location	Halifax, Canada
Auditor Firm Id	1263
Business Contact [Member]	
Entity Listings [Line Items]	
Contact Personnel Name	Emera US Finance LP
Entity Address, Address Line One	c/o Corporation Service Company
Entity Address Address Line Two	251 Little Falls Drive
Entity Address, City or Town	Wilmington
Entity Address, State or Province	DE
Entity Address, Postal Zip Code	19808
City Area Code	302

Local Phone Number	636-5401
Common Stock	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	284,117,511
Series A Preferred Stock	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	4,866,814
Series B Preferred Stock	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	1,133,186
Series C Preferred Stock	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	10,000,000
Series E Preferred Stock	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	5,000,000
Series F Preferred Stock	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	8,000,000
Series H Preferred Stock	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	12,000,000
Series J Preferred Stock [Member]	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	8,000,000
Series L Preferred Stock [Member]	
Entity Listings [Line Items]	
Entity Common Stock, Shares Outstanding	9,000,000

Consolidated Statements of Income - CAD ($) shares in Millions, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Operating revenues		
Total operating revenues (note 5)	$ 7,563.0	$ 7,588.0
Operating expenses		
Operating, maintenance and general expenses ("OM&G")	1,879.0	1,596.0
Provincial, state, and municipal taxes	433.0	367.0
Depreciation and amortization	1,049.0	952.0
GBPC Impairment charge (note 22)	0.0	73.0
Total operating expenses	5,769.0	5,959.0
Income from operations	1,794.0	1,629.0
Income from equity investments (note 7)	146.0	129.0
Other income, net (note 8)	158.0	145.0
Interest expense, net (note 9)	(925.0)	(709.0)
Income before provision for income taxes	1,173.0	1,194.0
Income tax expense (note 10)	128.0	185.0
Net income	1,045.0	1,009.0
Non-controlling interest in subsidiaries	1.0	1.0
Preferred stock dividends	66.0	63.0
Net income attributable to common shareholders	$ 977.7	$ 945.1
Earnings per common share (note 12)		
Basic	$ 3.57	$ 3.56
Diluted	$ 3.57	$ 3.55
Weighted average shares of common stock outstanding (in millions) (note 12)		
Basic	273.6	265.5
Diluted	273.8	265.9
Dividends per common share declared	$ 2.7875	$ 2.6775
Regulated | Gas Revenue		
Operating revenues		
Total operating revenues (note 5)	$ 1,489.0	$ 1,681.0
Operating expenses		
Fuel for generation and purchased power	527.0	800.0
Regulated | Electric Revenue		
Operating revenues		
Total operating revenues (note 5)	5,746.0	5,473.0
Operating expenses		
Fuel for generation and purchased power	1,881.0	2,171.0
Non-Regulated		
Operating revenues		
Total operating revenues (note 5)	$ 328.0	$ 434.0

Consolidated Statements of Comprehensive Income - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Consolidated Statements of Comprehensive Income		
Net income	$ 1,045	$ 1,009
Other comprehensive (loss) income, net of tax		
Foreign currency translation adjustment	(270)	629
Unrealized gains (losses) on net investment hedges	38	(97)
Cash flow hedges - reclassification adjustment for gains included in income	(2)	(2)
Cash flow hedges		
Unrealized losses on available-for-sale investment	0	(1)
Net change in unrecognized pension and post-retirement benefit obligation	(39)	24
Other comprehensive (loss) income	(273)	553
Comprehensive income	772	1,562
Comprehensive income attributable to non-controlling interest	1	1
Comprehensive Income of Emera Incorporated	$ 771	$ 1,561

Consolidated Statements of Comprehensive Income (Parenthetical) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Foreign currency translation, tax expense (recovery)	$ (7)	$ 7
Hybrid Notes as a hedge of the foreign currency exposure	1,200	1,100
Unrealized gains (losses) on net investment hedges	0	(6)
Net derivative gain, tax	0	(1)
Net change in unrecognized pension and post-retirement benefit obligation	1	1
Other comprehensive loss, Tax	(6)	$ 1
Net investment in United States dollar denominated operations		
Hybrid Notes as a hedge of the foreign currency exposure	$ 1,200	

Consolidated Balance Sheets - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Current assets		
Cash and cash equivalents	$ 567	$ 310
Restricted cash (note 32)	21	22
Inventory (note 14)	790	769
Derivative instruments (notes 15 and 16)	174	296
Regulatory assets (note 6)	339	602
Receivables and other current assets (note 18)	1,817	2,897
Total current assets	3,708	4,896
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $9,994 and $9,574, respectively (note 20)	24,376	22,996
Other assets		
Deferred income taxes (note 10)	208	237
Derivative instruments (notes 15 and 16)	66	100
Regulatory assets (note 6)	2,766	3,018
Net investment in direct finance and sales type leases (note 19)	621	604
Investments subject to significant influence (note 7)	1,402	1,418
Goodwill (note 22)	5,871	6,012
Other long-term assets (note 32)	462	461
Total other assets	11,396	11,850
Total assets	39,480	39,742
Current liabilities		
Short-term debt (note 23)	1,433	2,726
Current portion of long-term debt (note 25)	676	574
Accounts payable	1,454	2,025
Derivative instruments (notes 15 and 16)	386	888
Regulatory liabilities (note 6)	168	495
Other current liabilities (note 24)	427	579
Total current liabilities	4,544	7,287
Long-term liabilities		
Long-term debt (note 25)	17,689	15,744
Deferred income taxes (note 10)	2,352	2,196
Derivative instruments (notes 15 and 16)	118	190
Regulatory liabilities (note 6)	1,604	1,778
Pension and post-retirement liabilities (note 21)	265	281
Other long-term liabilities (notes 7 and 26)	820	825
Total long-term liabilities	22,848	21,014
Equity		
Common stock (note 11)	8,462	7,762
Cumulative preferred stock (note 28)	1,422	1,422
Contributed surplus	82	81
Accumulated other comprehensive income ("AOCI") (note 13)	305	578

Retained earnings	1,803	1,584
Total Emera Incorporated equity	12,074	11,427
Non-controlling interest in subsidiaries (note 29)	14	14
Total equity	12,088	11,441
Total liabilities and equity	$ 39,480	$ 39,742

Consolidated Balance Sheets (Parenthetical) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Consolidated Balance Sheets		
Accumulated depreciation and amortization on property, plant and equipment	$ 9,994	$ 9,574

Consolidated Statements of Cash Flows - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Operating activities		
Net income	$ 1,045	$ 1,009
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	1,060	959
Income from equity investments, net of dividends	(22)	(61)
Allowance for funds used during construction ("AFUDC") - equity	(38)	(52)
Deferred income taxes, net	97	152
Net change in pension and post-retirement liabilities	(68)	(48)
NSPI Fuel adjustment mechanism ("FAM")	(88)	(162)
Net change in Fair Value ("FV") of derivative instruments	(666)	206
Net change in regulatory assets and liabilities	554	(471)
Net change in capitalized transportation capacity	434	(445)
GBPC Impairment charge	0	73
Other operating activities, net	28	(13)
Changes in non-cash working capital (note 30)	(95)	(234)
Net cash provided by operating activities	2,241	913
Investing activities		
Additions to PP&E	(2,937)	(2,596)
Other investing activities	20	27
Net cash used in investing activities	(2,917)	(2,569)
Financing activities		
Change in short-term debt, net	(66)	1,028
Proceeds from short-term debt with maturities greater than 90 days	548	544
Repayment of short-term debt with maturities greater than 90 days	(1,086)	(680)
Proceeds from long-term debt, net of issuance costs	1,932	784
Retirement of long-term debt	(151)	(367)
Net (repayments) proceeds under committed credit facilities	(96)	511
Issuance of common stock, net of issuance costs	424	277
Dividends on common stock	(488)	(472)
Dividends on preferred stock	(66)	(63)
Other financing activities	(12)	(7)
Net cash provided by financing activities	939	1,555
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	(7)	16
Net increase (decrease) in cash, cash equivalents, and restricted cash	256	(85)
Cash, cash equivalents, and restricted cash, beginning of year	332	417
Cash, cash equivalents, and restricted cash, end of year	$ 588	$ 332

Consolidated Statements of Cash Flows (Parenthetical) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Cash, cash equivalents and restricted cash consists of:		
Cash	$ 559	$ 302
Short-term investments	8	8
Restricted cash	21	22
Cash, cash equivalents, and restricted cash	$ 588	$ 332

Consolidated Statements of Changes in Equity - CAD ($) $ in Millions	Total	Common Stock [Member]	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interest
Beginning Balance at Dec. 31, 2021	$ 10,150	$ 7,242	$ 1,422	$ 79	$ 25	$ 1,348	$ 34
Net income of Emera Inc.	1,009	0	0	0	0	1,008	1
Other comprehensive income (loss), net of tax expense	553	0	0	0	553	0	0
Dividends declared on preferred stock (note 28)	(63)	0	0	0	0	(63)	0
Dividends declared on common stock	(709)	0	0	0	0	(709)	0
Issued under the at-the-market program ("ATM"), net of after-tax issuance costs	248	248	0	0	0	0	0
Issued under the Dividend Reinvestment Program ("DRIP"), net of discount	238	238	0	0	0	0	0
Senior management stock options exercised and Employee Share Purchase Plan ("ECSPP")	36	34	0	2	0	0	0
Disposal of non-controlling interest of Dominica Electricity Services Ltd ("Domlec")	(20)	0	0	0	0	0	(20)
Other	(1)	0	0	0	0	0	(1)
Ending Balance at Dec. 31, 2022	11,441	7,762	1,422	81	578	1,584	14
Net income of Emera Inc.	1,045	0	0	0	0	1,044	1
Other comprehensive income (loss), net of tax expense	(273)	0	0	0	(273)	0	0
Dividends declared on preferred stock (note 28)	(66)	0	0	0	0	(66)	0
Dividends declared on common stock	(759)	0	0	0	0	(759)	0
Issued under the at-the-market program ("ATM"), net of after-tax issuance costs	397	397	0	0	0	0	0
Issued under the Dividend Reinvestment Program ("DRIP"), net of discount	272	272	0	0	0	0	0
Senior management stock options exercised and	32	31	0	1	0	0	0

Employee Share Purchase Plan ("ECSPP")							
Other	(1)	0	0	0	0	0	(1)
Ending Balance at Dec. 31, 2023	$ 12,088	$ 8,462	$ 1,422	$ 82	$ 305	$ 1,803	$ 14

Consolidated Statements of Changes in Equity (Parenthetical) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Consolidated Statements of Changes in Equity		
Other comprehensive loss, tax expense/recovery	$ (6)	$ 1
Dividends per common share declared	$ 2.7875	$ 2.6775

Summary of Significant Accounting Policies	12 Months Ended Dec. 31, 2023
Summary of Significant Accounting Policies [Abstract]	
Summary of Significant Accounting Policies	

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, 2023, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), a vertically integrated regulated electric utility, serving approximately 840,000 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 549,000 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, developed by Nalcor Energy. ENL's two investments are:
    - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion transmission project, including AFUDC; and
    - a 31 per cent equity interest in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador.

- Gas Utilities and Infrastructure, which includes:
  - Peoples Gas System Inc. ("PGS"), a regulated gas distribution utility, serving approximately 490,000 customers across Florida. Effective January 1, 2023, Peoples Gas System ceased to be a division of Tampa Electric Company and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 540,000 customers in New Mexico;
  - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership ("Repsol Energy"), which expires in 2034;
  - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida; and
  - a 12.9 per cent equity 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.

- 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 134,000 customers;
  - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 19,000 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.

- Emera’s other reportable segment includes investments in energy-related non-regulated companies which include:
  - 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 660 MW pumped storage hydroelectric facility in northwestern Massachusetts.
  - Emera US Finance LP (“Emera Finance”) and TECO Finance, Inc. (“TECO Finance”), financing subsidiaries of Emera;
  - Block Energy LLC (previously Emera Technologies LLC), a wholly owned technology company focused on finding ways to deliver renewable 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.

Basis of Presentation

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles (“USGAAP”) and in the opinion of management, 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 (“CAD”), unless otherwise indicated.

Principles of Consolidation

These consolidated financial statements include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity (“VIE”) in which Emera is the primary beneficiary. 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 VIE that most significantly impacts its economic performance and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. 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. For further details on VIEs, refer to note 32.

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 PP&E, regulatory assets, regulated fuel for generation and purchased power, or 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 reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations (“ARO”), and valuation of financial instruments. Management evaluates the Company’s estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. Rates are designed to recover prudently incurred costs of providing 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 6.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are converted to CAD 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 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 USD denominated debt held in CAD functional currency companies as hedges of net investments in USD denominated foreign operations. The change in the carrying amount of these investments, measured at exchange rates in effect at the balance sheet date is recorded in Other Comprehensive Income ("OCI").

Revenue Recognition

Regulated Electric and Gas Revenue:
Electric and gas 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 and gas are delivered to customers over time as the customer simultaneously receives and consumes the benefits. Electric and gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity and gas are recognized at rates approved by the respective regulators 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, electricity and gas delivered to customers, but not billed, is estimated and corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the megawatt hours ("MWh") or 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 energy demand, weather, line losses 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 the contract are satisfied and are presented on a net basis reflecting the nature of 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 the terms of the 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.

Franchise Fees and Gross Receipts

TEC 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 TEC 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.

PP&E

PP&E is recorded at original cost, including AFUDC or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units, are included in "PP&E" on the Consolidated Balance Sheets. When units of regulated PP&E 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 PP&E occurs, gains and losses are included in income as the dispositions occur.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, 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 and major maintenance projects that do not increase overall life of the related assets are expensed as incurred. 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 regulatory approval.

Intangible assets, which are included in "PP&E" on the Consolidated Balance Sheets, 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 FV 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 ("FX"). Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. 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 a qualitative assessment and determines it is more likely than not that its FV 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 FV of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its FV, an impairment loss is recorded. Management estimates the FV of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach uses a discounted cash flow analysis which relies on management's best estimate of the reporting unit's 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. For the market approach, management estimates FV based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the FV of a reporting unit using an income approach include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting unit's net operating loss ("NOL") and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera's reporting units.

As of December 31, 2023, $5,868 million of Emera's goodwill represents the excess of the acquisition purchase price for TECO Energy (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q4 2023, qualitative assessments were performed for NMGC and PGS given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2022 and Q4 2019, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result, no impairment charges were recognized.

In Q4 2022, as a result of a quantitative assessment, the Company recorded a goodwill impairment charge of $73 million, reducing the GBPC goodwill balance to nil as at December 31, 2022. For further details, 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 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 income tax assets will be recovered from future taxable income is assessed and assumptions are made about the expected timing of reversal of deferred income tax assets and liabilities. If management subsequently determines it is likely that some or all of a deferred income tax asset will not be realized, 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 on regulated assets by TEC, PGS and NMGC are deferred and amortized as required by regulatory practices.

TEC, PGS, NMGC and BLPC 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 regulators. 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 detail, refer to note 10.

Derivatives and Hedging Activities

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

The Company recognizes the FV 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 if the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, change in the FV of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Where documentation or effectiveness requirements are not met, the derivatives are recognized at FV with any changes in FV 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 FV 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. TEC has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases that ended on December 31, 2022 and was extended through December 31, 2024 as a result of TEC's 2021 rate case settlement agreement.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in FV 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 non-regulated operating revenues, fuel for generation and purchased power, other expenses, inventory, and OM&G, 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 FV 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".

Leases

The Company determines whether a contract contains a lease at inception by evaluating whether 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 for annual requirements to purchase wind and hydro energy over varying contract lengths which 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 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 FV 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.

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 recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Management estimates credit losses related to accounts receivable by 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.

Inventory

Fuel and materials inventories are valued at the lower of weighted-average cost or net realizable value, unless evidence indicates 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 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 FV. 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.

As at December 31, 2023, there are no indications of impairment of Emera's long-lived assets. No impairment charges related to long-lived assets were recognized in 2023 or 2022.

Equity Method Investments:
The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the FV of these investments to their carrying values, if a FV assessment was completed, or by reviewing for the presence of impairment indicators. 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 FV. No impairment of equity method investments was required in either 2023 or 2022.

Financial Assets:
Equity investments, other than those accounted for under the equity method, are measured at FV, with changes in FV recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable FV 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 2023 or 2022.

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 FV of 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 that are not recognized in the consolidated financial statements, as the FV of these obligations could not be reasonably estimated, given 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 FV in the period in which an amount can be determined.

Cost of Removal ("COR")

TEC, PGS, NMGC and NSPI recognize non-ARO 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 PP&E 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 FV-based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated FV 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 FV and re-measured at FV 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 unamortized gains and losses and past service costs in "AOCI" or "Regulatory assets" on the Consolidated Balance Sheets. 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. For further detail, refer to note 21.

Future Accounting Pronouncements	12 Months Ended Dec. 31, 2023
Future Accounting Pronouncements [Abstract]	
Future Accounting Pronouncements	

2. FUTURE ACCOUNTING PRONOUNCEMENTS

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

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The standard enhances the transparency, decision usefulness and effectiveness of income tax disclosures by requiring consistent categories and greater disaggregation of information in the reconciliation of income taxes computed using the enacted statutory income tax rate to the actual income tax provision and effective income tax rate, as well as the disaggregation of income taxes paid (refunded) by jurisdiction. The standard also requires disclosure of income (loss) before provision for income taxes and income tax expense (recovery) in accordance with U.S. Securities and Exchange Commission Regulation S-X 210.4-08(h), Rules of General Application – General Notes to Financial Statements: Income Tax Expense, and the removal of disclosures no longer considered cost beneficial or relevant. The guidance will be effective for annual reporting periods beginning after December 15, 2024, and interim periods within annual reporting periods beginning after December 15, 2025. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued ASU 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance will be effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied retrospectively. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

Dispositions	12 Months Ended Dec. 31, 2023
Dispositions [Abstract]	
Dispositions	**3. DISPOSITIONS** On March 31, 2022, Emera completed the sale of its 51.9 per cent interest in Domlec for proceeds which approximated its carrying value. Domlec was included in the Company’s Other Electric reportable segment up to its date of sale. The sale did not have a material impact on earnings.

Segment Information

12 Months Ended Dec. 31, 2023

Segment Information [Abstract]

Segment Information

4. 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.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2023							
Operating revenues from external customers (1)	$ 3,548	$ 1,671	$ 1,510	$ 526	$ 308	$ -	$ **7,563**
Inter-segment revenues (1)	8	-	14	-	31	(53)	**-**
Total operating revenues	3,556	1,671	1,524	526	339	(53)	**7,563**
Regulated fuel for generation and purchased power	920	699	-	275	-	(13)	**1,881**
Regulated cost of natural gas	-	-	527	-	-	-	**527**
OM&G	830	384	405	130	151	(21)	**1,879**
Provincial, state and municipal taxes	289	45	91	3	5	-	**433**
Depreciation and amortization	571	276	126	68	8	-	**1,049**
Income from equity investments	-	109	21	4	12	-	**146**
Other income, net	69	32	11	7	20	19	**158**
Interest expense, net (2)	271	170	129	23	332	-	**925**
Income tax expense (recovery)	117	(9)	64	-	(44)	-	**128**
Non-controlling interest in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	66	-	**66**
Net income (loss) attributable to common shareholders	$ 627	$ 247	$ 214	$ 37	$ (147)	$ -	$ **978**
Capital expenditures	$ 1,736	$ 450	$ 664	$ 63	$ 8	$ -	$ **2,921**
As at December 31, 2023							
Total assets	$ 21,119	$ 8,634	$ 7,735	$ 1,311	$ 1,938	$ (1,257)	$ **39,480**
Investments subject to significant influence	$ -	$ 1,236	$ 118	$ 48	$ -	$ -	$ **1,402**
Goodwill	$ 4,628	$ -	$ 1,240	$ -	$ 3	$ -	$ **5,871**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, 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 of $95 million for the year ended December 31, 2023, between the Florida Electric Utility, Gas Utilities and Infrastructure and Other segments.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2022							
Operating revenues from external customers (1)	$ 3,280	$ 1,675	$ 1,697	$ 518	$ 418	$ -	$ **7,588**
Inter-segment revenues (1)	7	-	7	-	22	(36)	**-**
Total operating revenues	3,287	1,675	1,704	518	440	(36)	**7,588**
Regulated fuel for generation and purchased power	1,086	803	-	290	-	(8)	**2,171**
Regulated cost of natural gas	-	-	800	-	-	-	**800**
OM&G	625	338	365	123	156	(11)	**1,596**
Provincial, state and municipal taxes	235	43	83	3	3	-	**367**
Depreciation and amortization	507	259	118	61	7	-	**952**
Income from equity investments	-	87	21	4	17	-	**129**
Other income (expenses), net	68	24	13	-	23	17	**145**
Interest expense, net (2)	185	136	81	19	288	-	**709**
GBPC impairment charge	-	-	-	73	-	-	**73**
Income tax expense (recovery)	121	(8)	70	-	2	-	**185**
Non-controlling interest in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	63	-	**63**
Net income (loss) attributable to common shareholders	$ 596	$ 215	$ 221	$ (48)	$ (39)	$ -	$ **945**
Capital expenditures	$ 1,425	$ 507	$ 574	$ 63	$ 6	$ -	$ **2,575**
As at December 31, 2022							
Total assets	$ 21,053	$ 8,223	$ 7,737	$ 1,337	$ 2,835	$ (1,443)	$ **39,742**
Investments subject to significant influence	$ -	$ 1,241	$ 128	$ 49	$ -	$ -	$ **1,418**
Goodwill	$ 4,739	$ -	$ 1,270	$ -	$ 3	$ -	$ **6,012**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, 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 of $13 million for the year ended December 31, 2022, between the Gas Utilities and Infrastructure and Other segments.

Geographical Information

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

For the millions of dollars	Year ended December 31 **2023**	2022
United States	**5,310**	$ 5,346
Canada	**1,727**	1,725
Barbados	**389**	384
The Bahamas	**137**	122
Dominica	**-**	11
	$ 7,563	$ 7,588

Property Plant and Equipment:

As at millions of dollars	**December 31 2023**	December 31 2022
United States	**$ 18,588**	$ 17,382
Canada	**4,878**	4,689
Barbados	**576**	583
The Bahamas	**334**	342
	$ 24,376	$ 22,996

Revenue	12 Months Ended Dec. 31, 2023
Revenue [Abstract]	
Revenue	

5. REVENUE

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

millions of dollars	Electric Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Gas Utilities and Infrastructure	Other Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2023							
Regulated Revenue							
Residential	$ 2,307	$ 910	$ 183	$ 724	$ -	$ -	$ 4,124
Commercial	1,083	463	285	425	-	-	2,256
Industrial	274	219	33	93	-	(13)	606
Other electric	395	41	7	-	-	-	443
Regulatory deferrals	(522)	-	12	-	-	-	(510)
Other (1)	19	38	6	199	-	(8)	254
Finance income (2)(3)	-	-	-	62	-		62
Regulated revenue	$ 3,556	$ 1,671	$ 526	$ 1,503	$ -	$ (21)	$ 7,235
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	96	-	96
Other non-regulated operating revenue	-	-	-	21	27	(23)	25
Mark-to-market (3)	-	-	-	-	216	(9)	207
Non-regulated revenue	$ -	$ -	$ -	$ 21	$ 339	$ (32)	$ 328
Total operating revenues	**$ 3,556**	**$ 1,671**	**$ 526**	**$ 1,524**	**$ 339**	**$ (53)**	**$ 7,563**
For the year ended December 31, 2022							
Regulated Revenue							
Residential	$ 1,799	$ 834	$ 184	$ 800	$ -	$ -	**$** 3,617
Commercial	869	427	282	461	-	-	2,039
Industrial	230	353	32	83	-	(7)	691
Other electric	398	28	6	-	-	-	432
Regulatory deferrals	(27)	-	6	-	-	-	(21)
Other (1)	18	33	8	283	-	(7)	335
Finance income (2)(3)	-	-	-	61	-	-	61
Regulated revenue	$ 3,287	$ 1,675	$ 518	$ 1,688	$ -	$ (14)	7,154
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	143	-	143
Other non-regulated operating revenue	-	-	-	16	16	(10)	22
Mark-to-market (3)	-	-	-	-	281	(12)	269
Non-regulated revenue	$ -	$ -	$ -	$ 16	$ 440	$ (22)	434
Total operating revenues	$ 3,287	$ 1,675	$ 518	$ 1,704	$ 440	$ (36)	$ 7,588

(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, 2023, the aggregate amount of the transaction price allocated to remaining performance obligations was $488 million (2022 – $450 million). This amount includes $134 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 2043.

Regulatory Assets and Liabilities	12 Months Ended Dec. 31, 2023
Regulatory Assets and Liabilities [Abstract]	
Regulatory Assets and Liabilities	(see below)

6. 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, 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 dollars		**December 31 2023**		December 31 2022
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,233**	$	1,166
TEC capital cost recovery for early retired assets		**671**		674
NSPI FAM		**395**		307
Pension and post-retirement medical plan		**364**		369
Cost recovery clauses		**151**		707
Deferrals related to derivative instruments		**88**		30
Storm cost recovery clauses		**52**		138
Environmental remediations		**26**		27
Stranded cost recovery		**25**		27
NMGC winter event gas cost recovery		**-**		69
Other		**100**		106
	$	**3,105**	$	3,620
Current	**$**	**339**	$	602
Long-term		**2,766**		3,018
Total regulatory assets	**$**	**3,105**	$	3,620
Regulatory liabilities				
Accumulated reserve – COR		**849**		895
Deferred income tax regulatory liabilities		**830**		877
Cost recovery clauses		**32**		70
BLPC Self-insurance fund ("SIF") (note 32)		**29**		30
Deferrals related to derivative instruments		**17**		230
NMGC gas hedge settlements (note 18)		**-**		162
Other		**15**		9
	$	**1,772**	$	2,273
Current	**$**	**168**	$	495
Long-term		**1,604**		1,778
Total regulatory liabilities	**$**	**1,772**	$	2,273

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.

TEC 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 is 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. For further information, refer to "Big Bend Modernization Project" in the TEC section below.

NSPI FAM

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through regularly scheduled 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 and recovered from or returned to customers in subsequent periods.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at TEC, PGS and NMGC. It is included in rate base and earns a rate of return as permitted by the FPSC and NMPRC, as applicable. It is amortized over the remaining service life of plan participants.

Cost Recovery Clauses

These assets and liabilities are related to TEC, PGS and NMGC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or New Mexico Public Regulation Commission ("NMPRC"), as applicable, on a dollar-for-dollar basis in a subsequent period.

Deferrals Related to Derivative Instruments

This asset is primarily related to NSPI deferring changes in FV 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 the UARB. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, other income, inventory, or OM&G, depending on the nature of the item being economically hedged.

Storm Cost Recovery Clauses

TEC and PGS Storm Reserve:
The storm reserve is for hurricanes and other named storms that cause significant damage to TEC and PGS systems. As allowed by the FPSC, if charges to the storm reserve exceed the storm liability, the excess is to be carried as a regulatory asset. TEC 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 2022, TEC and PGS were impacted by Hurricane Ian. For further information, refer to "TEC Storm Reserve" in the Florida Electric Utility section below.

NSPI Storm Rider:
NSPI has a UARB approved storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the UARB for recovery of costs if major storm restoration expenses exceed approximately $10 million in a given year.

GBPC Storm Restoration:
This asset represents storm restoration costs 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 recovery of $15 million USD of 2019 costs related to Hurricane Dorian, over a five-year period from 2021 through 2025.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge. For further information, refer to "Storm Restoration Costs – Hurricane Matthew" in the GBPC section below.

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

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 ("PGAC"). On June 15, 2021, the NMPRC approved recovery of $108 million USD and related borrowing costs in customer rates over a period of 30 months from July 1, 2021, to December 31, 2023.

Accumulated Reserve – COR

This regulatory liability represents the non-ARO COR reserve in TEC, PGS, NMGC and NSPI. AROs represent the FV of estimated cash flows associated with the Company's legal obligation to retire its PP&E. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E 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.

NMGC Gas Hedge Settlements

This regulatory liability represents regulatory deferral of gas options exercised above strike price but settled subsequent to the period end. The value from cash settlement of these options flows to customers via the PGAC.

Other Regulatory Assets and Liabilities

Comprised of regulatory assets and liabilities that are not individually significant.

Regulatory Environments and Updates

Florida Electric Utility

TEC is regulated by the FPSC and is also subject to regulation by the Federal Energy Regulatory Commission. The FPSC sets rates at a level that allows utilities such as TEC 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 TEC, the FPSC or other interested parties.

TEC's approved regulated return on equity ("ROE") range for 2023 and 2022 was 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.20 per cent (2022 – 10.20 per cent) is used for the calculation of the return on investments for clauses.

Base Rates:
On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 million USD for 2026 and 2027, respectively. TEC's proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC's ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

Fuel Recovery and Other Cost Recovery Clauses:
TEC 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 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 subsequent periods.

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

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

Big Bend Modernization Project:
TEC invested $876 million USD, including $91 million USD of AFUDC, between 2018 and 2022 to modernize the Big Bend Power Station. The modernization project repowered Big Bend Unit 1 with natural gas combined-cycle technology and eliminated coal as this unit's fuel. As part of the modernization project, TEC in 2020 retired the Unit 1 components that would not be used in the modernized plant and did the same for Big Bend Unit 2 in 2021. TEC retired Big Bend Unit 3 in 2023 as it was in the best interests of the customers from an economic, environmental risk and operational perspective. On December 31, 2021, the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, of $636 million USD and $267 million USD in accumulated depreciation were reclassified to a regulatory asset on the balance sheet.

TEC's 2021 settlement agreement provides for cost recovery of the Big Bend Modernization project in two phases. The first phase was a revenue increase to cover the costs of the assets in service during 2022, among other items. The remainder of the project costs were recovered as part of the 2023 subsequent year adjustment. The settlement agreement also includes a new charge to recover the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, which are spread over 15 years, effective January 1, 2022. This recovery mechanism was authorized by and survives the term of the settlement agreement approved by the FPSC in 2021.

Storm Reserve:
In September 2022, TEC was impacted by Hurricane Ian, with $119 million USD of restoration costs charged against TEC's FPSC approved storm reserve. Total restoration costs charged to the storm reserve exceeded the reserve balance and have been deferred as a regulatory asset for future recovery.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the FPSC approved TEC's petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings.

Storm Protection Cost Recovery Clause and Settlement Agreement:
The Storm Protection Plan ("SPP") Cost Recovery Clause provides a process for Florida investor-owned utilities, including TEC, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. 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. A settlement agreement was approved on August 10, 2020, and TEC's cost recovery began in January 2021. The current approved plan addressed the years 2023, 2024 and 2025 and was approved by the FPSC on October 4, 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 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's approved regulated ROE range for 2023 and 2022 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 of approved rate base.

General Rate Application ("GRA"):
On February 2, 2023, the UARB approved the GRA settlement agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and further average increases of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB's established FAM process. It also established a storm rider and a demand-side management rider. On March 27, 2023, the UARB issued a final order approving the electricity rates effective on February 2, 2023.

Fuel Recovery:
For the period of 2020 through 2022, NSPI operated under a three-year fuel stability plan with no fuel rate adjustments related to the under-recovery of fuel and fuel-related costs in the period.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding FAM balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024.

Storm Rider:
The storm rider was effective as of the GRA decision date. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application. Total major storm restoration expense for 2023 was $31 million, of which $21 million was deferred to the storm rider.

Hurricane Fiona:
On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023, the $24 million is deferred to "Other long-term assets", pending UARB approval.

Maritime Link:
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. Any difference between the amounts recovered from customers through rates and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

Nova Scotia Cap-and-Trade ("Cap-and-Trade") Program:
As of December 31, 2022, the FAM included a cumulative $166 million in fuel costs related to the accrued purchase of emissions credits and $6 million related to credits purchased from provincial auctions. On March 16, 2023, the Province of Nova Scotia provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 period. As such, compliance costs accrued of $166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of $6 million were not refunded and no further costs were incurred to achieve compliance with the Cap-and-Trade Program.

Extra Large Industrial Active Demand Tariff:
On July 5, 2023, NSPI received approval from the UARB to change the methodology in which fuel cost recovery from an industrial customer is calculated. Due to significant volatility in commodity prices in 2022, the previous methodology did not result in a reasonable determination of the fuel cost to serve this customer. The change in methodology, effective January 1, 2022, results in a shifting of fuel costs from this industrial customer to the FAM. This adjustment was recorded in Q2 2023 resulting in a $51 million increase to the FAM regulatory asset and an offsetting decrease to unbilled revenue within Receivables and other current assets. This adjustment had minimal impact on earnings.

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 Nova Scotia Block ("NS Block") delivery obligations commenced on August 15, 2021 and delivery will continue over the next 35 years pursuant to the agreements.

In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion less $9 million of costs ($7 million after-tax) that would not have otherwise been recoverable if incurred by NSPI.

On October 4, 2023 and January 31, 2024, the UARB issued decisions providing clarification on remaining aspects of the Maritime Link holdback mechanism primarily relating to release of past and future holdback amounts and requirements to end the holdback mechanism. In these decisions, the UARB agreed with the Company's submission that $12 million ($8 million related to 2022 and $4 million relating to 2023) of the previously recorded holdback remain credited to NSPI's FAM, with the remainder released to NSPML and recorded in Emera's "Income from equity investments. NSPML did not record any additional holdback in Q4 2023. The UARB also confirmed that the holdback mechanism will cease once 90 per cent of NS Block deliveries are achieved for 12 consecutive months (subject to potential relief for planned outages or exceptional circumstances) and the net outstanding balance of previously underdelivered NS Block energy is less than 10 per cent of the contracted annual amount. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023.

On December 21, 2023, NSPML received approval to collect up to $164 million (2023 – $164 million) from NSPI for the recovery of costs associated with the Maritime Link in 2024; subject to a holdback of up to $4 million a month, as discussed above.

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 2023 and 2022 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.

Base Rates:
On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

The 2020 PGS rate case settlement provided the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

Fuel Recovery:
PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its PGAC. 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.

Recovery of Energy Conservation and Pipeline Replacement Programs:
The FPSC annually approves a conservation charge that is intended to permit PGS to recover prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are required by Florida law and approved and monitored by the FPSC. PGS also 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. The majority of cast iron and bare steel pipe has been removed from its system, 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.

NMGC’s approved ROE for 2023 and 2022 was 9.375 per cent on an allowed equity capital structure of 52 per cent.

Base Rates:
On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective Q4 2024. NMGC requested $49 million USD in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent.

Fuel Recovery:
NMGC recovers gas supply costs through a PGAC. This clause recovers 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 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. NMGC received approval of its PGAC Continuation in December 2020, for the four-year period ending December 2024.

Integrity Management Programs (“IMP”) Regulatory Asset:
A portion of NMGC’s annual spending on infrastructure is for 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 petitioned recovery of the regulatory asset in its rate case filed on December 13, 2021. On November 30, 2022, the NMPRC issued a Final Order that included approval of recovery of the IMP regulatory asset.

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Saint John 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 North America Canada Partnership. 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.

Other Electric Utilities

BLPC

BLPC is regulated by the Fair Trading Commission ("FTC"), under the Utilities Regulation (Procedural) Rules 2003. BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's approved regulated return on rate base was 10 per cent for 2023 and 2022.

Licenses:
BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

Base Rates:
In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the "Motion") and applied for a stay of the FTC's decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

On December 1, 2023, BLPC appealed certain aspects of the FTC's February 15 and November 20, 2023, decisions to the Supreme Court of Barbados in the High Court of Justice (the "Court") and requested that they be stayed. On December 11, 2023, the Court granted the stay. BLPC's position is that the FTC made errors of law and jurisdiction in their decisions and believes the success of the appeal is probable, and as a result, the adjustments to BLPC's final rates and rate base, including any adjustments to regulatory assets and liabilities, have not been recorded at this time.

Fuel Recovery:
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 calculation of the fuel charge is adjusted on a monthly basis and reported to the FTC for approval.

Clean Energy Transition Program ("CETP"):
On May 31, 2023, the FTC approved BLPC's application to establish an alternative cost recovery mechanism to recover prudently incurred costs associated with its CETP (the "Decision"). The mechanism is intended to facilitate the timely recovery between rate cases of costs associated with approved renewable energy assets. BLPC will be required to submit an individual application for the recovery of costs of each asset through the cost recovery mechanism, meeting the minimum criteria as set out in the Decision. On October 5, 2023, BLPC applied to the FTC to recover the costs of a battery storage system through the CETP.

Fuel Hedging:
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.

GBPC

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. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. GBPC's approved regulated return on rate base was 8.32 per cent for 2023 (2022 – 8.23 per cent).

Base Rates:
There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. 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 became effective April 1, 2022, allows for an increase in revenues of $3.5 million USD. The rates include a regulatory ROE of 12.84 per cent.

Fuel Recovery:
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.

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

Storm Restoration Costs – Hurricane Matthew:
As part of the recovery of costs incurred as a result of Hurricane Matthew, in 2016, 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. As part of its decision on GBPC's application for rate review, 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.

Investments Subject to Significant Influence and Equity Income	12 Months Ended
	Dec. 31, 2023
Investments Subject to Significant Influence and Equity Income [Abstract]	
Investments Subject to Significant Influence and Equity Income	

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of dollars	Carrying Value As at December 31 2023	2022	Equity Income For the year ended December 31 2023	2022	Percentage of Ownership 2023
LIL (1)	**$ 747**	$ 740	**$ 63**	$ 58	**31.0**
NSPML	**489**	501	**46**	29	**100.0**
M&NP (2)	**118**	128	**21**	21	**12.9**
Lucelec (2)	**48**	49	**4**	4	**19.5**
Bear Swamp (3)	**-**	-	**12**	17	**50.0**
	$ 1,402	$ 1,418	**$ 146**	$ 129	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.5 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) Emera has significant influence over the operating and financial decisions of these companies through Board representation and therefore, 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 $81 million (2022 – $95 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

Equity investments include a $10 million difference between the cost and the underlying FV 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 dollars	December 31 2023	2022
Balance Sheets		
Current assets	**$ 21**	$ 17
PP&E	**1,473**	1,517
Regulatory assets	**272**	265
Non-current assets	**29**	29
Total assets	**$ 1,795**	$ 1,828
Current liabilities	**$ 48**	$ 48
Long-term debt (1)	**1,109**	1,149
Non-current liabilities	**149**	130
Equity	**489**	501
Total liabilities and equity	**$ 1,795**	$ 1,828

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

Other Income, Net	12 Months Ended Dec. 31, 2023
Other Income, Net [Abstract]	
Other Income, Net	

8. OTHER INCOME, NET

For the millions of dollars	Year ended December 31 2023	2022
Interest income	**$ 43**	$ 25
AFUDC	**38**	52
Pension non-current service cost recovery	**35**	24
FX gains (losses)	**20**	(26)
TECO Guatemala Holdings award (1)	**-**	63
Other	**22**	7
	$ 158	$ 145

(1) On December 15, 2022, a payment of $63 million was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment in TGH, a wholly-owned subsidiary of TECO Energy.

Interest Expense, Net	12 Months Ended Dec. 31, 2023
Interest Expense, Net [Abstract]	
Interest Expense, Net	**9. INTEREST EXPENSE, NET**

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Year ended December 31 **2023**	2022
Interest on debt	**$ 954**	$ 727
Allowance for borrowed funds used during construction	**(16)**	(21)
Other	**(13)**	3
	$ 925	$ 709

Income Taxes	12 Months Ended Dec. 31, 2023
Income Taxes [Abstract]	
Income Taxes	

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 dollars		**2023**		2022
Income before provision for income taxes	**$**	**1,173**	$	1,194
Statutory income tax rate		**29.0%**		29.0%
Income taxes, at statutory income tax rate		**340**		346
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		**(72)**		(70)
Tax credits		**(53)**		(18)
Foreign tax rate variance		**(36)**		(44)
Amortization of deferred income tax regulatory liabilities		**(33)**		(33)
Tax effect of equity earnings		**(15)**		(10)
GBPC impairment charge		**-**		21
Other		**(3)**		(7)
Income tax expense	**$**	**128**	$	185
Effective income tax rate		**11%**		15%

On August 16, 2022, the United States Inflation Reduction Act ("IRA") was signed into legislation. The IRA includes numerous tax incentives for clean energy, such as the extension and modification of existing investment and production tax credits for projects placed in service through 2024 and introduces new technology-neutral clean energy related tax credits beginning in 2025. As of December 31, 2023, the Company has recorded a $30 million (2022 - $9 million) regulatory liability on the Consolidated Balance Sheets in recognition of its obligation to pass the incremental tax benefits realized to customers.

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 dollars		**2023**		2022
Current income taxes				
Canada	**$**	**26**	$	25
United States		**5**		8
Deferred income taxes				
Canada		**93**		122
United States		**128**		252
Investment tax credits				
United States		**(29)**		(7)
Operating loss carryforwards				
Canada		**(93)**		(94)
United States		**(2)**		(121)
Income tax expense	**$**	**128**	$	185

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 dollars		**2023**		2022
Canada	**$**	**171**	$	173
United States		**964**		1,063
Other		**38**		(42)
Income before provision for income taxes	**$**	**1,173**	$	1,194

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

millions of dollars		**2023**		2022
Deferred income tax assets:				
Tax loss carryforwards	**$**	**1,195**	$	1,207
Tax credit carryforwards		**454**		415
Derivative instruments		**205**		45
Regulatory liabilities		**175**		264
Other		**372**		341
Total deferred income tax assets before valuation allowance		**2,401**		2,272
Valuation allowance		**(363)**		(312)
Total deferred income tax assets after valuation allowance	**$**	**2,038**	$	1,960
Deferred income tax (liabilities):				
PP&E	**$**	**(3,223)**	$	(2,981)
Derivative instruments		**(235)**		(125)
Investments subject to significant influence		**(216)**		(181)
Regulatory assets		**(196)**		(310)
Other		**(312)**		(322)
Total deferred income tax liabilities	**$**	**(4,182)**	$	(3,919)
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets	**$**	**208**	$	237
Long-term deferred income tax liabilities		**(2,352)**		(2,196)
Net deferred income tax liabilities	**$**	**(2,144)**	$	(1,959)

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 long-term debt and investments. A valuation allowance of $363 million has been recorded as at December 31, 2023 (2022 – $312 million) related to the loss carryforwards, long-term debt and investments.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, as at December 31, 2023, $4.7 billion (2022 – $3.8 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 NOL, capital loss and tax credit carryforwards and their expiration periods as at December 31, 2023 consisted of the following:

millions of dollars		Tax Carryforwards		Subject to Valuation Allowance		Net Tax Carryforwards	Expiration Period
Canada							
NOL	$	2,914	$	(1,164)	$	1,750	2026 - 2043
Capital loss		73		(73)		-	Indefinite
United States							
Federal NOL	$	1,360	$	(1)	$	1,359	2036 - Indefinite
State NOL		1,003		(1)		1,002	2026 - Indefinite
Tax credit		454		(3)		451	2025 - 2043
Other							
NOL	$	81	$	(28)	$	53	2024 - 2030

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

millions of dollars		**2023**		2022
Balance, January 1	**$**	**33**	$	28
Increases due to tax positions related to current year		**5**		5
Increases due to tax positions related to a prior year		**1**		2
Decreases due to tax positions related to a prior year		**(2)**		(2)
Balance, December 31	**$**	**37**	$	33

Unrecognized tax benefits relate to the timing of certain tax deductions at NSPI and research and development tax credits primarily at TEC. The total amount of unrecognized tax benefits as at December 31, 2023 was $37 million (2022 – $33 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $9 million (2022 – $7 million) with $2 million interest expense recognized in the Consolidated Statements of Income (2022 – $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.

During 2022, the CRA issued notices of reassessment to NSPI for the 2013 through 2016 taxation years. NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 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 $126 million (2022 – $126 million), including interest. NSPI has prepaid $55 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 of the 2006 through 2010 taxation years. 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 difference, if any, either owed to, or refunded from, the 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 Notice of Appeal process is not determinable at this time.

Emera files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, and St. Lucia income tax returns. As at December 31, 2023, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

Common Stock	12 Months Ended Dec. 31, 2023
Common Stock [Abstract]	
Common Stock	(see below)

11. COMMON STOCK

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

Issued and outstanding:	2023 millions of shares	2023 millions of dollars	2022 millions of shares	2022 millions of dollars
Balance, January 1	**269.95**	**$ 7,762**	261.07	$ 7,242
Issuance of common stock under ATM program (1)(2)	**8.29**	**397**	4.07	248
Issued under the DRIP, net of discounts	**5.26**	**272**	4.21	238
Senior management stock options exercised and Employee Share Purchase Plan	**0.62**	**31**	0.60	34
Balance, December 31	**284.12**	**$ 8,462**	269.95	$ 7,762

(1) For the year ended December 31, 2022, a total of 4,072,469 common shares were issued under Emera's ATM program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs).
(2) For the year ended December 31, 2023, a total of 8,287,037 common shares were issued under Emera's ATM program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs).

As at December 31, 2023, the following common shares were reserved for issuance: 6 million (2022 – 6 million) under the senior management stock option plan, 2 million (2022 – 2.7 million) under the employee common share purchase plan and 18 million (2022 – 10 million) under the 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, 2023, Emera was in compliance with this requirement.

ATM Equity Program

On October 3, 2023, Emera filed a short form base shelf prospectus, primarily in support of the renewal of its ATM Program in Q4 2023 that will allow 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. This ATM Program is expected to remain in effect until November 4, 2025.

Earnings Per Share	12 Months Ended Dec. 31, 2023
Earnings Per Share [Abstract]	
Earnings Per Share	## 12. EARNINGS PER SHARE Basic earnings per share is determined by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares 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 DRIP. The following table reconciles the computation of basic and diluted earnings per share:

For the millions of dollars (except per share amounts)	Year ended December 31 **2023**	2022
Numerator		
Net income attributable to common shareholders	**$ 977.7**	$ 945.1
Diluted numerator	**977.7**	945.1
Denominator		
Weighted average shares of common stock outstanding – basic	**273.6**	265.5
Stock-based compensation	**0.2**	0.4
Weighted average shares of common stock outstanding – diluted	**273.8**	265.9
Earnings per common share		
Basic	**$ 3.57**	$ 3.56
Diluted	**$ 3.57**	$ 3.55

Accumulated Other Comprehensive Income	12 Months Ended Dec. 31, 2023
Accumulated Other Comprehensive Income [Abstract]	
Accumulated Other Comprehensive Income	

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of AOCI are as follows:

millions of dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	Losses 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, 2023						
Balance, January 1, 2023	**$ 639**	**$ (62)**	**$ 16**	**$ (2)**	**$ (13)**	**$ 578**
Other comprehensive (loss) income before reclassifications	**(270)**	**38**	**-**	**-**	**-**	**(232)**
Amounts reclassified from AOCI	**-**	**-**	**(2)**	**-**	**(39)**	**(41)**
Net current period other comprehensive (loss) income	**(270)**	**38**	**(2)**	**-**	**(39)**	**(273)**
Balance, December 31, 2023	**$ 369**	**$ (24)**	**$ 14**	**$ (2)**	**$ (52)**	**$ 305**
For the year ended December 31, 2022						
Balance, January 1, 2022	$ 10	$ 35	$ 18	$ (1)	$ (37)	$ 25
Other comprehensive income (loss) before reclassifications	629	(97)	-	(1)	-	531
Amounts reclassified from AOCI	-	-	(2)	-	24	22
Net current period other comprehensive income (loss)	629	(97)	(2)	(1)	24	553
Balance, December 31, 2022	$ 639	$ (62)	$ 16	$ (2)	$ (13)	$ 578

The reclassifications out of AOCI are as follows:

For the millions of dollars	Affected line item in the Consolidated Financial Statements	Year ended December 31 **2023**	2022
Gains on derivatives recognized as cash flow hedges			
Interest rate hedge	Interest expense, net	**$ (2)**	$ (2)
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses	Other income, net	**$ -**	$ 10
Past service costs	Other income, net	**2**	-
Amounts reclassified into obligations	Pension and post-retirement benefits	**(40)**	15
Total before tax		**(38)**	25
Income tax expense		**(1)**	(1)
Total net of tax		**$ (39)**	$ 24
Total reclassifications out of AOCI, net of tax, for the period		**$ (41)**	$ 22

Inventory	12 Months Ended Dec. 31, 2023
Inventory [Abstract]	
Inventory	**14. INVENTORY**

As at millions of dollars	**December 31 2023**	December 31 2022
Fuel	**$ 382**	$ 404
Materials	**408**	365
Total	**$ 790**	$ 769

Derivative Instruments

Derivative Instruments

Derivative Instruments

12 Months Ended Dec. 31, 2023

15. DERIVATIVE INSTRUMENTS

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

As at millions of dollars	Derivative Assets **December 31 2023**	Derivative Assets December 31 2022	Derivative Liabilities **December 31 2023**	Derivative Liabilities December 31 2022
Regulatory deferral:				
Commodity swaps and forwards	**$ 16**	$ 186	**$ 76**	$ 42
FX forwards	**3**	18	**3**	1
Physical natural gas purchases and sales	**-**	52	**-**	-
	19	256	**79**	43
HFT derivatives:				
Power swaps and physical contracts	**29**	89	**36**	77
Natural gas swaps, futures, forwards, physical contracts	**319**	340	**531**	1,224
	348	429	**567**	1,301
Other derivatives:				
Equity derivatives	**4**	-	**-**	5
FX forwards	**18**	5	**7**	23
	22	5	**7**	28
Total gross current derivatives	**389**	690	**653**	1,372
Impact of master netting agreements:				
Regulatory deferral	**(3)**	(18)	**(3)**	(18)
HFT derivatives	**(146)**	(276)	**(146)**	(276)
Total impact of master netting agreements	**(149)**	(294)	**(149)**	(294)
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078
Current (1)	**174**	296	**386**	888
Long-term (1)	**66**	100	**118**	190
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078

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

Cash Flow Hedges

On May 26, 2021, a treasury lock was settled for a gain of $19 million that is being amortized through interest expense over 10 years as the underlying hedged item settles.

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

For the millions of dollars	Year ended December 31 **2023** **Interest rate hedge**	2022 Interest rate hedge
Realized gain in interest expense, net	**$ 2**	$ 2
Total gains in net income	**$ 2**	$ 2

As at millions of dollars	**December 31 2023** **Interest rate hedge**	December 31 2022 Interest rate hedge
Total unrealized gain in AOCI – effective portion, net of tax	**$ 14**	$ 16

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 with respect to derivatives receiving regulatory deferral:

millions of dollars	Physical natural gas purchases	Commodity swaps and forwards	FX forwards	Physical natural gas purchases	Commodity swaps and forwards	FX forwards
For the year ended December 31			**2023**			2022
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (109)**	**$ (3)**	$ -	$ (69)	$ 1
Unrealized gain (loss) in regulatory liabilities	**(3)**	**(73)**	**-**	28	343	16
Realized (gain) loss in regulatory assets	**-**	**(5)**	**-**	-	48	-
Realized (gain) loss in regulatory liabilities	**-**	**2**	**-**	-	(41)	-
Realized (gain) loss in inventory (1)	**-**	**4**	**(10)**	-	(121)	1
Realized (gain) in regulated fuel for generation and purchased power (2)	**(49)**	**(9)**	**(4)**	(64)	(146)	**-**
Other	**-**	**(14)**	**-**	-	-	-
Total change in derivative instruments	**$ (52)**	**$ (204)**	**$ (17)**	$ (36)	$ 14	$ 18

(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.

As at December 31, 2023, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2024	2025-2026
Physical natural gas purchases:		
Natural gas (MMBtu)	7	6
Commodity swaps and forwards purchases:		
Natural gas (MMBtu)	16	10
Power (MWh)	1	1
Coal (metric tonnes)	1	-
FX swaps and forwards:		
FX contracts (millions of USD)	$ 241	$ 70
Weighted average rate	1.3155	1.3197
% of USD requirements	63%	17%

HFT Derivatives

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

For the millions of dollars	Year ended December 31 **2023**	2022
Power swaps and physical contracts in non-regulated operating revenues	**$ (6)**	$ 17
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**1,043**	47
Total gains in net income	**$ 1,037**	$ 64

As at December 31, 2023, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2024	2025	2026	2027	2028 and thereafter
Natural gas purchases (Mmbtu)	296	80	50	38	30
Natural gas sales (Mmbtu)	338	86	16	6	4
Power purchases (MWh)	1	-	-	-	-
Power sales (MWh)	1	-	-	-	-

Other Derivatives

As at December 31, 2023, the Company had equity derivatives in place to manage the cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and FX forwards in place to manage cash flow risk associated with forecasted USD cash inflows. The equity derivatives hedge the return on 2.9 million shares and extends until December 2024. The FX forwards have a combined notional amount of $508 million USD and expire in 2023, 2024 and 2025.

For the millions of dollars	**2023** FX Forwards	Year ended December 31 Equity Derivatives	FX Forwards	2022 Equity Derivatives
Unrealized gain (loss) in OM&G	**$ -**	**$ 4**	$ -	$ (5)
Unrealized gain (loss) in other income, net	**28**	**-**	(18)	-
Realized loss in OM&G	**-**	**(13)**	-	(17)
Realized loss in other income, net	**(11)**	**-**	(6)	-
Total gains (losses) in net income	**$ 17**	**$ (9)**	$ (24)	$ (22)

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, 2023, the maximum exposure the Company had to credit risk was $1.2 billion (2022 – $1.9 billion), which included 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, FX 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, 2023 was $310 million (2022 – $386 million), which mitigated 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, North American Energy Standards Board agreements and, or Edison Electric Institute agreements. The Company believes entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2023, the Company had $142 million (2022 – $131 million) in financial assets, considered to be past due, which have been outstanding for an average 64 days. The FV of these financial assets was $127 million (2022 – $114 million), the difference of which was 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, 2023		December 31, 2022	
		millions of dollars	**% of total exposure**	millions of dollars	% of total exposure
Receivables, net					
Regulated utilities:					
Residential	**$**	**476**	**31%**	$ 455	19%
Commercial		**194**	**13%**	192	8%
Industrial		**84**	**5%**	121	5%
Other		**103**	**7%**	122	5%
Cash collateral		**94**	**6%**	-	0%
		951	**62%**	890	37%
Trading group:					
Credit rating of A- or above		**47**	**3%**	125	5%
Credit rating of BBB- to BBB+		**33**	**2%**	75	3%
Not rated		**108**	**7%**	307	13%
		188	**12%**	507	21%
Other accounts receivable		**151**	**10%**	585	25%
		1,290	**84%**	1,982	83%
Derivative Instruments (current and long-term)					
Credit rating of A- or above		**138**	**9%**	202	9%
Credit rating of BBB- to BBB+		**7**	**1%**	8	0%
Not rated		**95**	**6%**	186	8%
		240	**16%**	396	17%
	$	**1,530**	**100%**	$ 2,378	100%

Cash Collateral

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

As at	December 31	December 31
millions of dollars	**2023**	2022
Cash collateral provided to others	**$ 101**	$ 224
Cash collateral received from others	**$ 22**	$ 112

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, 2023, the total FV of derivatives in a liability position was $504 million (December 31, 2022 – $1,078 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.

FV Measurements	12 Months Ended Dec. 31, 2023
FV Measurements [Abstract]	
Fair Value Measurements	

16. FV MEASUREMENTS

The Company is required to determine the FV 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 FV 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 FV measurement.

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

As at				December 31, 2023
millions of dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 7	$ 6	$ -	$ 13
FX forwards	-	3	-	3
	7	9	-	16
HFT derivatives:				
Power swaps and physical contracts	(5)	23	-	18
Natural gas swaps, futures, forwards, physical contracts and related transportation	42	108	34	184
	37	131	34	202
Other derivatives:				
FX forwards	-	18	-	18
Equity derivatives	4	-	-	4
	4	18	-	22
Total assets	48	158	34	240
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	43	30	-	73
FX forwards	-	3	-	3
	43	33	-	76
HFT derivatives:				
Power swaps and physical contracts	-	24	-	24
Natural gas swaps, futures, forwards and physical contracts	13	19	365	397
	13	43	365	421
Other derivatives:				
FX forwards	-	7	-	7
	-	7	-	7
Total liabilities	56	83	365	504
Net assets (liabilities)	$ (8)	$ 75	$ (331)	$ (264)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2022 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 120	$ 48	$ -	$ 168
FX forwards	-	18	-	18
Physical natural gas purchases and sales	-	-	52	52
	120	66	52	238
HFT derivatives:				
Power swaps and physical contracts	9	31	4	44
Natural gas swaps, futures, forwards, physical contracts and related transportation	3	72	34	109
	12	103	38	153
Other derivatives:				
FX forwards	-	5	-	5
Total assets	132	174	90	396
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	15	9	-	24
FX forwards	-	1	-	1
	15	10	-	25
HFT derivatives:				
Power swaps and physical contracts	2	28	1	31
Natural gas swaps, futures, forwards and physical contracts	51	118	825	994
	53	146	826	1,025
Other derivatives:				
FX forwards	-	23	-	23
Equity derivatives	5	-	-	5
Total liabilities	73	179	826	1,078
Net assets (liabilities)	$ 59	$ (5)	$ (736)	$ (682)

The change in the FV of the Level 3 financial assets for the year ended December 31, 2023 was as follows:

millions of dollars	***Regulatory Deferral*** **Physical natural gas purchases**	***HFT Derivatives*** **Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 52**	**$ 4**	**$ 34**	**$ 90**
Realized gains (losses) included in fuel for generation and purchased power	**(49)**	**-**	**-**	**(49)**
Unrealized gains (losses) included in regulatory assets and liabilities	**(3)**	**-**	**-**	**(3)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(4)**	**-**	**(4)**
Balance, December 31, 2023	**$ -**	**$ -**	**$ 34**	**$ 34**

The change in the FV of the Level 3 financial liabilities for the year ended December 31, 2023 was as follows:

millions of dollars	***HFT Derivatives*** **Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 1**	**$ 825**	**$ 826**
Total realized and unrealized gains included in non-regulated operating revenues	**(1)**	**(460)**	**(461)**
Balance, December 31, 2023	**$ -**	**$ 365**	**$ 365**

Significant unobservable inputs used in the FV measurement of Emera's natural gas and power derivatives include third-party sourced pricing for instruments based on illiquid markets. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) FV measurement. Other unobservable inputs used include 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.

The Company uses a modelled pricing valuation technique for determining the FV of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the FV measurements categorized within Level 3 of the FV hierarchy:

millions of dollars	FV Assets	FV Liabilities	Significant Unobservable Input	Low	High	Weighted average (1)
As at December 31, 2023						
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**34**	**365**	Third-party pricing	$1.27	$16.25	$4.85
Total	**$ 34**	**$ 365**				
Net liability		**$ 331**				
As at December 31, 2022						
Regulatory deferral – Physical natural gas purchases	$ 52	$ -	Third-party pricing	$5.79	$31.85	$12.27
HFT derivatives – Power swaps and physical contracts	4	1	Third-party pricing	$43.24	$269.10	$138.79
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	34	825	Third-party pricing	$2.45	$33.88	$12.01
Total	$ 90	$ 826				
Net liability		$ 736				

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

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

As at millions of dollars	Carrying Amount	FV	Level 1	Level 2	Level 3	Total
December 31, 2023	**$ 18,365**	**$ 16,621**	**$ -**	**$ 16,363**	**$ 258**	**$ 16,621**
December 31, 2022	$ 16,318	$ 14,670	$ -	$ 14,284	$ 386	$ 14,670

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, 2023, the FV of the Hybrid Notes was $1.2 billion (2022 – $1.1 billion). An after-tax foreign currency gain of $38 million was recorded in AOCI for the year ended December 31, 2023 (2022 – $97 million after-tax loss).

Related Party Transactions	12 Months Ended Dec. 31, 2023
Related Party Transactions [Abstract]	
Related Party Transactions	**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 $163 million for the year ended December 31, 2023 (2022 – $157 million). NSPML is accounted for as an equity investment, and therefore 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 $14 million for the year ended December 31, 2023 (2022 – $9 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, 2023 and at December 31, 2022.

Receivables and Other Current Assets	12 Months Ended Dec. 31, 2023
Receivables and Other Current Assets [Abstract]	
Receivables and Other Current Assets	

18. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars		**December 31 2023**		December 31 2022
Customer accounts receivable – billed	**$**	**805**	$	1,096
Capitalized transportation capacity (1)		**358**		781
Customer accounts receivable – unbilled		**363**		424
Prepaid expenses		**105**		82
Income tax receivable		**10**		9
Allowance for credit losses		**(15)**		(17)
NMGC gas hedge settlement receivable (2)		**-**		162
Other		**191**		360
Total receivables and other current assets	**$**	**1,817**	$	2,897

(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.
(2) Offsetting amount is included in regulatory liabilities for NMGC as gas hedges are part of the PGAC. For more information, refer to note 6.

Leases	12 Months Ended Dec. 31, 2023
Leases [Abstract]	
Leases, Lessee	

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 62 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain they will be exercised.

As at		**December 31**	December 31
millions of dollars	Classification	**2023**	2022
Right-of-use asset	Other long-term assets	**$ 54**	$ 58
Lease liabilities			
Current	Other current liabilities	**3**	3
Long-term	Other long-term liabilities	**55**	59
Total lease liabilities		**$ 58**	$ 62

The Company recorded lease expense of $127 million for the year ended December 31, 2023 (2022 – $138 million), of which $119 million (2022 – $131 million) related 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 dollars	2024	2025	2026	2027	2028	Thereafter	Total
Minimum lease payments	$ 6	$ 5	$ 3	$ 3	$ 3	$ 111	$ 131
Less imputed interest							(73)
Total							$ 58

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

	Year ended December 31	
For the	**2023**	2022
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of dollars)	**$ 8**	$ 8
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of dollars)	**$ 1**	$ 1
Weighted average remaining lease term (years)	**44**	44
Weighted average discount rate- operating leases	**3.93%**	3.98%

Lessor

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

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 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.

Commencing in October 2023, the Company leased a RNG facility to a biogas producer that is classified as a sales-type lease. The term of the facility lease is 15 years, with a nominal value purchase at the end of the term and a net investment of approximately $35 million USD.

Commencing in January 2022, the Company leased Seacoast pipeline, a 21-mile, 30-inch lateral that is classified as a sales-type lease. The term of the pipeline lateral lease is 34 years with a net investment of $100 million USD. The lessee of the pipeline lateral has renewal options for an additional 16 years. These renewal options have not been included as part of the pipeline lateral lease term as it is not reasonably certain that they will be exercised.

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

As at millions of dollars		**December 31 2023**		December 31 2022
Total minimum lease payment to be received	**$**	**1,360**	$	1,393
Less: amounts representing estimated executory costs		**(190)**		(205)
Minimum lease payments receivable	**$**	**1,170**	$	1,188
Estimated residual value of leased property (unguaranteed)		**183**		183
Less: Credit loss reserve		**(2)**		-
Less: unearned finance lease income		**(693)**		(733)
Net investment in direct finance and sales-type leases	**$**	**658**	$	638
Principal due within one year (included in "Receivables and other current assets")		**37**		34
Net Investment in direct finance and sales type leases - long-term	**$**	**621**	$	604

As at December 31, 2023, future minimum lease payments to be received for each of the next five years and in aggregate thereafter were as follows:

millions of dollars		2024		2025		2026		2027		2028		Thereafter		Total
Minimum lease payments to be received	$	97	$	99	$	98	$	97	$	96	$	873	$	1,360
Less: executory costs														(190)
Total													$	1,170

Property, Plant and Equipment	12 Months Ended Dec. 31, 2023
Property, Plant and Equipment [Abstract]	
Property, Plant and Equipment	(see below)

20. PROPERTY, PLANT AND EQUIPMENT

PP&E consisted of the following regulated and non-regulated assets:

As at millions of dollars	Estimated useful life		**December 31 2023**		December 31 2022
Generation	3 to 131	**$**	**13,500**	$	13,083
Transmission	10 to 80		**2,835**		2,731
Distribution	4 to 80		**7,417**		6,978
Gas transmission and distribution	6 to 92		**5,536**		5,061
General plant and other (1)	2 to 71		**2,985**		2,723
Total cost			**32,273**		30,576
Less: Accumulated depreciation (1)			**(9,994)**		(9,574)
			22,279		21,002
Construction work in progress (1)			**2,097**		1,994
Net book value		**$**	**24,376**	$	22,996

(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, 2023, SeaCoast's share of plant in service was $27 million USD (2022 – $27 million USD), and accumulated depreciation of $2 million USD (2022 – $1 million USD). 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.

Employee Benefit Plans	12 Months Ended Dec. 31, 2023
Employee Benefit Plans [Abstract]	
Employee Benefit Plans	

21. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit ("DB") and defined-contribution ("DC") 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, and Grand Bahama Island.

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 dollars	**2023**		Year ended December 31 2022	
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	**$ 2,158**	**$ 243**	$ 2,624	$ 318
Service cost	**30**	**3**	41	4
Plan participant contributions	**6**	**6**	6	6
Interest cost	**111**	**13**	80	9
Plan amendments	**-**	**(14)**	-	-
Benefits paid	**(147)**	**(29)**	(174)	(31)
Actuarial losses (gains)	**146**	**10**	(480)	(79)
Settlements and curtailments	**(8)**	**-**	(6)	-
FX translation adjustment	**(23)**	**(5)**	67	16
Balance, December 31	**$ 2,273**	**$ 227**	$ 2,158	$ 243
Change in plan assets				
Balance, January 1	**$ 2,163**	**$ 46**	$ 2,702	$ 51
Employer contributions	**42**	**23**	45	24
Plan participant contributions	**6**	**6**	6	6
Benefits paid	**(147)**	**(29)**	(174)	(31)
Actual return on assets, net of expenses	**262**	**3**	(489)	(7)
Settlements and curtailments	**(8)**	**-**	(6)	**-**
FX translation adjustment	**(20)**	**(1)**	79	3
Balance, December 31	**$ 2,298**	**$ 48**	$ 2,163	$ 46
Funded status, end of year	**$ 25**	**$ (179)**	$ 5	$ (197)

The actuarial losses recognized in the period are primarily due to changes in the discount rate, higher than expected indexation, and compensation-related assumption changes.

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) exceeded the plan assets for the years ended December 31 was as follows:

millions of dollars	**2023**		2022	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 120**	**$ 205**	$ 1,006	$ 221
FV of plan assets	**37**	**-**	914	-
Funded status	**$ (83)**	**$ (205)**	$ (92)	$ (221)

Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets:

The ABO for the DB pension plans was $2,172 million as at December 31, 2023 (2022 – $2,080 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 was as follows:

millions of dollars	**2023**	2022
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 114**	$ 111
FV of plan assets	**37**	33
Funded status	**$ (77)**	$ (78)

Balance Sheet:

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

As at millions of dollars	**December 31 2023** **Defined benefit pension plans**	**Non-pension benefit plans**	December 31 2022 Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	**$ (5)**	**$ (18)**	$ (13)	$ (20)
Long-term liabilities	**(78)**	**(187)**	(80)	(201)
Other long-term assets	**108**	**26**	98	24
AOCI, net of tax and regulatory assets	**385**	**20**	358	22
Less: Deferred income tax (expense) recovery in AOCI	**(8)**	**(1)**	(7)	(1)
Net amount recognized	**$ 402**	**$ (160)**	$ 356	$ (176)

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 dollars	Regulatory assets	Actuarial (gains) losses	Past service (gains) costs
Defined Benefit Pension Plans			
Balance, January 1, 2023	$ 336	$ 15	$ -
Amortized in current period	(6)	(3)	-
Current year additions	1	41	-
Change in FX rate	(7)	-	-
Balance, December 31, 2023	$ 324	$ 53	$ -
Non-pension benefits plans			
Balance, January 1, 2023	$ 31	$ (10)	$ -
Amortized in current period	2	3	-
Current year reductions	(3)	(1)	(3)
Change in FX rate	(1)	-	1
Balance, December 31, 2023	$ 29	$ (8)	$ (2)

As at millions of dollars	**December 2023** **Defined benefit pension plans**	**Non-pension benefit plans**	December 2022 Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	**$ 53**	**(8)**	$ 15	$ (10)
Past service gains	**-**	**(2)**	-	-
Deferred income tax expense	**8**	**1**	7	1
AOCI, net of tax	**61**	**(9)**	22	(9)
Regulatory assets	**324**	**29**	336	31
AOCI, net of tax and regulatory assets	**$ 385**	**$ 20**	$ 358	$ 22

Benefit Cost Components:

Emera's net periodic benefit cost included the following:

As at millions of dollars	Year ended December 31 **2023** **Defined benefit pension plans**	**Non-pension benefit plans**	2022 Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 30**	**$ 3**	$ 41	$ 4
Interest cost	**111**	**13**	80	9
Expected return on plan assets	**(161)**	**(2)**	(144)	-
Current year amortization of:				
Actuarial losses (gains)	**1**	**(3)**	8	-
Regulatory assets (liability)	**6**	**(2)**	21	2
Settlement, curtailments	**2**	**-**	2	-
Total	**$ (11)**	**$ 9**	$ 8	$ 15

The expected return on plan assets is determined based on the market-related value of plan assets of $2,577 million as at January 1, 2023 (2022 – $2,482 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	10%
Fixed income	34%	to	49%
Equities:			
Canadian	7%	to	17%
Non-Canadian	35%	to	59%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average		
Cash and cash equivalents	0%	to	10%
Fixed income	29%	to	49%
Equities	48%	to	68%

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 FV its investments:

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
As at					**December 31, 2023**
Cash and cash equivalents	**$ -**	**$ 40**	**$ -**	**$ 40**	**2 %**
Net in-transits	**-**	**(9)**	**-**	**(9)**	**- %**
Equity securities:					
Canadian equity	**-**	**96**	**-**	**96**	**4 %**
United States equity	**-**	**141**	**-**	**141**	**6 %**
Other equity	**-**	**112**	**-**	**112**	**5 %**
Fixed income securities:					
Government	**-**	**-**	**172**	**172**	**8 %**
Corporate	**-**	**-**	**90**	**90**	**4 %**
Other	**-**	**4**	**5**	**9**	**- %**
Mutual funds	**-**	**50**	**-**	**50**	**2 %**
Other	**-**	**6**	**(1)**	**5**	**- %**
Open-ended investments measured at NAV (1)	**1,006**	**-**	**-**	**1,006**	**44 %**
Common collective trusts measured at NAV (2)	**586**	**-**	**-**	**586**	**25 %**
Total	**$ 1,592**	**$ 440**	**$ 266**	**$ 2,298**	**100 %**
As at					December 31, 2022
Cash and cash equivalents	$ -	$ 70	$ -	$ 70	3 %
Net in-transits	-	(70)	-	(70)	(3)%
Equity securities:					
Canadian equity	-	87	-	87	4 %
United States equity	-	233	-	233	11 %
Other equity	-	186	-	186	8 %
Fixed income securities:					
Government	-	-	104	104	5 %
Corporate	-	-	83	83	4 %
Other	-	3	11	14	1 %
Mutual funds	-	68	-	68	3 %
Other	-	-	(3)	(3)	- %
Open-ended investments measured at NAV (1)	790	-	-	790	36 %
Common collective trusts measured at NAV (2)	601	-	-	601	28 %
Total	$ 1,391	$ 577	$ 195	$ 2,163	100 %

(1) Net asset value ("NAV") investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated at least monthly and the funds honour 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 honour subscription and redemption activity regularly.

Refer to note 16 for more information on the FV hierarchy and inputs used to measure FV.

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 exception to this is the NMGC Retiree Medical Plan, which is fully funded.

Investments in Emera:
As at December 31, 2023 and 2022, assets related to the pension funds and post-retirement benefit plans did 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 expected cash flows for DB pension and other post-retirement benefit plans:

millions of dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2024	$ 34	$ 19
Expected benefit payments		
2024	172	21
2025	163	21
2026	166	21
2027	171	21
2028	173	20
2029 – 2033	890	95

Assumptions:

The following table shows the assumptions that have been used in accounting for DB pension and other post-retirement benefit plans:

	2023		2022	
(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	**4.89 %**	**4.89 %**	5.33 %	5.31 %
Discount rate - future service	**4.88 %**	**4.89 %**	5.34 %	5.32 %
Rate of compensation increase	**3.87 %**	**3.85 %**	3.62 %	3.61 %
Health care trend - initial (next year)	**-**	**6.04 %**	-	5.40 %
- ultimate	**-**	**3.76 %**	-	3.77 %
- year ultimate reached		**2043**		2043
Benefit cost for year ended December 31:				
Discount rate - past service	**5.33 %**	**5.31 %**	3.05 %	2.81 %
Discount rate - future service	**5.34 %**	**5.32 %**	3.18 %	2.92 %
Expected long-term return on plan assets	**6.56 %**	**2.16 %**	6.07 %	1.32 %
Rate of compensation increase	**3.62 %**	**3.61 %**	3.31 %	3.29 %
Health care trend - initial (current year)	**-**	**5.40 %**	-	5.09 %
- ultimate	**-**	**3.77 %**	-	3.77 %
- year ultimate reached		**2043**		2042

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 DC pension plan for certain employees. The Company's contribution for the year ended December 31, 2023 was $45 million (2022 – $41 million).

Goodwill	12 Months Ended Dec. 31, 2023
Goodwill [Abstract]	
Goodwill	**22. GOODWILL**

22. GOODWILL

The change in goodwill for the year ended December 31 was due to the following:

millions of dollars		**2023**		2022
Balance, January 1	**$**	**6,012**	$	5,696
Change in FX rate		**(141)**		389
GBPC impairment charge		**-**		(73)
Balance, December 31	**$**	**5,871**	$	6,012

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, 2023, primarily related to TECO Energy (reporting units with goodwill are TEC, PGS, and NMGC).

In 2023, Emera performed qualitative impairment assessments for NMGC and PGS, concluding that the FV of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessments were performed and no impairment charges were recognized. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income approach and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result no impairment charges were recognized.

In 2022, the Company elected to bypass a qualitative assessment and performed a quantitative impairment assessment for GBPC, using the income approach. It was determined that the FV did not exceed its carrying amount, including goodwill. As a result of this assessment, a goodwill impairment charge of $73 million was recorded in 2022, reducing the GBPC goodwill balance to nil as at December 31, 2022. This non-cash charge is included in "GBPC impairment charge" on the Consolidated Statements of Income.

Short-Term Debt	12 Months Ended Dec. 31, 2023
Short-Term Debt [Abstract]	
Short-Term Debt	

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 dollars	**2023**	**Weighted average interest rate**	2022	Weighted average interest rate
TEC				
Advances on revolving credit facilities	**$ 277**	**5.68 %**	$ 1,380	5.00 %
Emera				
Non-revolving term facilities	**796**	**6.07 %**	796	5.19 %
Bank indebtedness	**9**	**- %**	-	- %
TECO Finance				
Advances on revolving credit and term facilities	**245**	**6.54 %**	481	5.47 %
PGS				
Advances on revolving credit facilities	**73**	**6.36 %**	-	- %
NMGC				
Advances on revolving credit facilities	**25**	**6.46 %**	59	5.15 %
GBPC				
Advances on revolving credit facilities	**8**	**5.54 %**	10	5.25 %
Short-term debt	**$ 1,433**		$ 2,726	

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 dollars	Maturity	**2023**	2022
TEC - Unsecured committed revolving credit facility	2026	**$ 401**	$ 1,084
TECO Energy/TECO Finance - revolving credit facility	2026	**-**	542
TECO Finance - Unsecured committed revolving credit facility	2026	**529**	-
Emera - Unsecured non-revolving term facility	2024	**400**	400
Emera - Unsecured non-revolving term facility	2024	**400**	400
PGS - Unsecured revolving credit facility	2028	**331**	-
TEC - Unsecured revolving facility	2024	**265**	542
TEC - Unsecured revolving facility	2024	**265**	-
NMGC - Unsecured revolving credit facility	2026	**165**	169
Other - Unsecured committed revolving credit facilities	Various	**17**	18
Total		**$ 2,773**	$ 3,155
Less:			
Advances under revolving credit and term facilities		**1,433**	2,731
Letters of credit issued within the credit facilities		**3**	4
Total advances under available facilities		**1,436**	2,735
Available capacity under existing agreements		**$ 1,337**	$ 420

The weighted average interest rate on outstanding short-term debt at December 31, 2023 was 5.95 per cent (2022 – 5.01 per cent).

Recent Significant Financing Activity by Segment

Florida Electric Utilities

On November 24, 2023, TEC repaid its $400 million USD unsecured non-revolving facility, which expired on December 13, 2023.

On April 3, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on April 1, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term secured overnight financing rate ("SOFR"), Wells Fargo's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

On March 1, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on February 28, 2024. The credit facility contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term SOFR, the Bank of Nova Scotia's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

Gas Utilities and Infrastructure

On December 1, 2023, PGS entered into a $250 million USD senior unsecured revolving credit facility with a group of banks, maturing on December 1, 2028. PGS has the ability to request the lenders to increase their commitments under the credit facility by up to $100 million USD in the aggregate subject to agreement from participating lenders. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin.

Other

On December 16, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from December 16, 2023 to December 16, 2024. There were no other changes in commercial terms from the prior agreement.

On June 30, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from August 2, 2023 to August 2, 2024. There were no other changes in commercial terms from the prior agreement.

Other Current Liabilities	12 Months Ended Dec. 31, 2023

Other Current Liabilities

Other Current Liabilities

24. OTHER CURRENT LIABILITIES

As at millions of dollars		December 31 2023		December 31 2022
Accrued charges	**$**	**172**	$	174
Nova Scotia Cap-and-Trade Program provision (note 6)		**-**		172
Accrued interest on long-term debt		**107**		97
Pension and post-retirement liabilities (note 21)		**23**		33
Sales and other taxes payable		**11**		14
Income tax payable		**2**		9
Other		**112**		80
	$	**427**	$	579

Long-Term Debt	12 Months Ended Dec. 31, 2023
Long-term Debt [Abstract]	
Long-term Debt	

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 dollars	Weighted average interest rate (1) 2023	2022	Maturity		2023		2022
Emera							
Bankers acceptances, SOFR loans	Variable	Variable	2027	**$**	**465**	$	403
Unsecured fixed rate notes	4.84%	2.90%	2030		**500**		500
Fixed to floating subordinated notes (2)	6.75%	6.75%	2076		**1,587**		1,625
				$	**2,552**	$	2,528
Emera Finance							
Unsecured senior notes	3.65%	3.65%	2024 - 2046	**$**	**3,637**	$	3,725
TEC (3)							
Fixed rate notes and bonds	4.61%	4.15%	2024 - 2051	**$**	**5,654**	$	4,341
PGS							
Fixed rate notes and bonds	5.63%	3.78%	2028 - 2053	**$**	**1,223**	$	772
NMGC							
Fixed rate notes and bonds	3.78%	3.11%	2026 - 2051	**$**	**642**	$	521
Non-revolving term facility, floating rate	Variable	Variable	2024		**30**		108
				$	**672**	$	629
NMGI							
Fixed rate notes and bonds	3.64%	3.64%	2024	**$**	**198**	$	203
NSPI							
Discount Notes (4)	Variable	Variable	2024 - 2027	**$**	**721**	$	881
Medium term fixed rate notes	5.13%	5.14%	2025 - 2097		**3,165**		2,665
				$	**3,886**	$	3,546
EBP							
Senior secured credit facility	Variable	Variable	2026	**$**	**246**	$	249
ECI							
Secured senior notes	Variable	Variable	2027	**$**	**75**	$	86
Amortizing fixed rate notes	4.00%	3.97%	2026		**79**		100
Non-revolving term facility, floating rate	Variable	Variable	2025		**29**		30
Non-revolving term facility, fixed rate	2.15%	2.05%	2025 - 2027		**155**		91
Secured fixed rate senior notes (5)	3.09%	3.06%	2024 - 2029		**84**		142
				$	**422**	$	449
Adjustments							
Fair market value adjustment - TECO Energy acquisition				**$**	**-**	$	2
Debt issuance costs					**(125)**		(126)
Amount due within one year					**(676)**		(574)
				$	**(801)**	$	(698)
Long-Term Debt				**$**	**17,689**	$	15,744

(1) Weighted average interest rate of fixed rate long-term debt.
(2) In 2023, the Company recognized $109 million in interest expense (2022 – $110 million) related to its fixed to floating subordinated notes.
(3) A substantial part of TEC's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under TEC's first mortgage bond indenture.
(4) Discount notes are backed by a revolving credit facility which matures in 2027. Banker's acceptances are issued under NSPI's non-revolving term facility which matures in 2024. NSPI has the intention and unencumbered ability to refinance bankers' acceptances for a period of greater than one year.
(5) Notes are issued and payable in either USD or BBD.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of dollars	Maturity	2023	2022
Emera – revolving credit facility (1)	June 2027	**$ 900**	$ 900
TEC - Unsecured committed revolving credit facility	December 2026	**657**	-
NSPI - revolving credit facility (1)	December 2027	**800**	800
NSPI - non-revolving credit facility	July 2024	**400**	400
Emera - Unsecured non-revolving credit facility	February 2024	**400**	-
NMGC - Unsecured non-revolving credit facility	March 2024	**30**	108
ECI – revolving credit facilities	October 2024	**10**	11
Total		**$ 3,197**	$ 2,219
Less:			
Borrowings under credit facilities		**1,884**	1,396
Letters of credit issued inside credit facilities		**6**	12
Use of available facilities		**$ 1,890**	$ 1,408
Available capacity under existing agreements		**$ 1,307**	$ 811

(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, 2023
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 January 30, 2024, TEC issued $500 million USD of senior unsecured bonds that bear interest at 4.90 per cent with a maturity date of March 1, 2029. Proceeds from the issuance were primarily used for repayment of short-term borrowings outstanding under the 5-year credit facility. Therefore, $497 million USD of short-term borrowings that were repaid was classified as long-term debt at December 31, 2023.

Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053.

Gas Utilities and Infrastructure

On December 19, 2023, PGS completed an issuance of $925 million USD in senior notes. The issuance included $350 million USD senior notes that bear interest at 5.42 per cent with a maturity date of December 19, 2028, $350 million USD senior notes that bear interest at 5.63 per cent with a maturity date of December 19, 2033 and $225 million USD senior notes that bear interest at 5.94 per cent with a maturity date of December 19, 2053.

On October 19, 2023, NMGC issued $100 million USD in senior unsecured notes that bear interest at 6.36 per cent with a maturity date of October 19, 2033.

Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028.

Other

On August 18, 2023, Emera entered into a $400 million non-revolving term facility with a maturity date of February 19, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. On February 16, 2024, Emera extended the term of this agreement to a maturity date of February 19, 2025.

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030.

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 dollars	2024	2025	2026	2027	2028	Thereafter	Total
Emera	$ 199	$ -	$ 1,587	$ 266	$ -	$ 500	$ 2,552
Emera US Finance LP	397	-	992	-	-	2,248	3,637
TEC	397	-	-	-	-	5,257	5,654
PGS	-	-	-	-	463	760	1,223
NMGC	30	-	93	-	-	549	672
NMGI	198	-	-	-	-	-	198
NSPI	398	125	40	323	-	3,000	3,886
EBP	-	-	246	-	-	-	246
ECI	51	139	89	77	62	4	422
Total	$ 1,670	$ 264	$ 3,047	$ 666	$ 525	$ 12,318	$ 18,490

Asset Retirement Obligations	12 Months Ended Dec. 31, 2023
Asset Retirement Obligations [Abstract]	
Asset Retirement Obligations	

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 FV of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of dollars		2023		2022
Balance, January 1	**$**	**174**	$	174
Accretion included in depreciation expense		**9**		9
Change in FX rate		**(1)**		3
Additions		**-**		1
Accretion deferred to regulatory asset (included in PP&E)		**18**		1
Liabilities settled		**(8)**		(1)
Revisions in estimated cash flows		**-**		(13)
Balance, December 31	**$**	**192**	$	174

Commitments and Contingencies	12 Months Ended Dec. 31, 2023
Commitments and Contingencies Disclosure [Abstract]	
Commitments and Contingencies	

27. COMMITMENTS AND CONTINGENCIES

Commitments

As at December 31, 2023, 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 dollars	2024	2025	2026	2027	2028	Thereafter	Total
Transportation (1)	$ 696	$ 495	$ 405	$ 388	$ 338	$ 2,597	$ 4,919
Purchased power (2)	274	249	263	312	312	3,435	4,845
Fuel, gas supply and storage	556	215	62	-	5	-	838
Capital projects	778	111	70	1	-	-	960
Equity investment commitments (3)	240	-	-	-	-	-	240
Other	154	147	56	46	35	221	659
	$ 2,698	$ 1,217	$ 856	$ 747	$ 690	$ 6,253	$ 12,461

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $134 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) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion. In December 2023, the UARB approved the collection of up to $164 million from NSPI for the recovery of Maritime Link costs in 2024. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Construction of the LIL is complete, and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

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 and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Other" in the above table.

Legal Proceedings

Superfund and Former Manufactured Gas Plant Sites

Previously, TEC had been a potentially responsible party ("PRP") for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, Peoples Gas System, Inc. is also now a PRP for those sites (in addition to third party PRPs for certain sites). While the aggregate joint and several liability associated with these sites has not changed as a result of the PGS legal separation, the sites continue to present the potential for significant response costs. As at December 31, 2023, the aggregate financial liability of the Florida utilities is estimated to be $15 million ($11 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 the Florida utilities. The estimates to perform the work are based on the Florida utilities' 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, the Florida utilities could be liable for more than their 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.

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 FV 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 an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee ("ERMC") and monitored by the Board of Directors, to ensure an effective, consistent and coherent approach to risk management. The Board of Directors has a Risk and Sustainability Committee ('RSC") with a mandate that 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.

Regulatory and Political Risk

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

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

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

Emera's utilities generally manage this risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries work to establish collaborative relationships with regulatory stakeholders, including customer representatives, both through its approach to filings and additional efforts with technical conferences and, where appropriate, negotiated settlements.

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

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

Foreign Exchange Risk

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

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

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries do not impact net income as they are reported in 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.

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

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

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

General Economic Risk

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

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

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

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Market Risk".

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

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

Commodity Price Risk

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

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

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

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

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

To measure commodity price risk exposure, Emera Energy employs a number of controls and processes, including an estimated VaR analysis of its exposures. The VaR amount represents an estimate of the potential change in FV 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 income 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.

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, 2023:

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 Investor Services ("Moody's") or S&P Global Ratings ("S&P"). TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

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

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

NSPI has issued guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of $104 million USD (2022 – $119 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $103 million USD (December 31, 2022 – $145 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 2024. The amount committed as at December 31, 2023 was $56 million (December 31, 2022 – $63 million).

Collaborative Arrangements

For the years ended December 31, 2023 and 2022, 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" on the Consolidated Statements of Income. In 2023, NSPI recognized $8 million net expense (2022 – $12 million) in "Regulated fuel for generation and purchased power" and $3 million (2022 – $3 million) in "OM&G" on the Consolidated Statements of Income.

Cumulative Preferred Stock	12 Months Ended Dec. 31, 2023
Cumulative Preferred Stock [Abstract]	
Cumulative Preferred Stock	

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, 2023		December 31, 2022	
	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	$ 1.6085	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 25.00	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0505	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Series H	$ 1.5810	$ 25.00	**12,000,000**	**$ 295**	12,000,000	$ 295
Series J	$ 1.0625	$ 25.00	**8,000,000**	**$ 196**	8,000,000	$ 196
Series L	$ 1.1500	$ 26.00	**9,000,000**	**$ 222**	9,000,000	$ 222
Total			**58,000,000**	**$ 1,422**	58,000,000	$ 1,422

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 (5)(6)	4.100	1.6085	2.65	August 15, 2028	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 (5)(7)	4.900	1.5810	4.90	August 15, 2028	25.00	Series I
Series J	4.250	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate						
Series E (8)	4.500	1.1250			25.00	
Series L (9)	4.600	1.1500		November 15, 2026	26.00	

(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, 2028, February 15, 2025 and August 15, 2028, 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) On July 6, 2023, Emera announced it would not redeem the outstanding Preferred Shares, Series C and Series H on August 15, 2023. On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C Shares were converted into Series D Shares and no Series H Shares were converted into Series I shares.

(6) The annual fixed dividend per share for Series C Shares was reset from $1.1802 to $1.6085 for the five-year period from and including August 15, 2028.

(7) The annual fixed dividend per share for Series H Shares was reset from $1.2250 to $1.5810 for the five-year period from and including August 15, 2028.

(8) First Preferred Shares, Series E are redeemable at $25.00 per share.

(9) 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 are deducted on the Consolidated Statements of Income before arriving at “Net income attributable to common shareholders” and shown on the Consolidated Statement of Changes in 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.

Non-Controlling Interest in Subsidiaries	12 Months Ended Dec. 31, 2023
Non-Controlling Interest in Subsidiaries [Abstract]	
Non-Controlling Interest in Subsidiaries	(see below)

29. NON-CONTROLLING INTEREST IN SUBSIDIARIES

As at millions of dollars	**December 31 2023**	December 31 2022
Preferred shares of GBPC	**$ 14**	$ 14
	$ 14	$ 14

Preferred shares of GBPC:

Authorized:
10,000 non-voting cumulative redeemable variable perpetual preferred shares.

	2023		2022	
Issued and outstanding:	**number of shares**	**millions of dollars**	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.

Supplementary Information to Consolidated Statements of Cash Flows	12 Months Ended
	Dec. 31, 2023
Supplementary Information to Consolidated Statements of Cash Flows [Abstract]	
Supplementary Information to Consolidated Statements of Cash Flows	(see below)

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the			Year ended December 31	
millions of dollars		**2023**		2022
Changes in non-cash working capital:				
Inventory	**$**	**(31)**	$	(214)
Receivables and other current assets (1)		**653**		(636)
Accounts payable		**(538)**		423
Other current liabilities (2)		**(179)**		193
Total non-cash working capital	**$**	**(95)**	$	(234)

(1) Includes $162 million related to the January 2023 settlement of NMGC gas hedges (2022 – ($162) million). Offsetting regulatory liability is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
(2) Includes ($166) million related to the Nova Scotia Cap-and-Trade program (2022 – $172 million). For further detail, refer to note 6. Offsetting regulatory asset (FAM) balance is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.

For the			Year ended December 31	
millions of dollars		**2023**		2022
Supplemental disclosure of cash paid:				
Interest	**$**	**930**	$	699
Income taxes	**$**	**43**	$	67
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**271**	$	237
Decrease in accrued capital expenditures	**$**	**(19)**	$	(13)
Reclassification of short-term debt to long-term debt	**$**	**657**	$	-
Reclassification of long-term debt to short-term debt	**$**	**-**	$	500
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	**$**	**123**	$	(157)

Stock Based Compensation	12 Months Ended Dec. 31, 2023
Stock-Based Compensation [Abstract]	
Stock-based Compensation	

31. STOCK-BASED COMPENSATION

Employee Common Share Purchase Plan and Common Shareholders Dividend Reinvestment and Share Purchase Plan

Eligible employees may participate in the ECSPP. As of December 31, 2023, 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 reinvestment of dividends for all participants except where prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares. As at December 31, 2023, Emera was in compliance with this requirement.

Compensation cost for shares issued under the ECSPP for the year ended December 31, 2023 was $3 million (2022 – $3 million) and was included in "OM&G" on the Consolidated Statements of Income.

The Company also has a Common Shareholders DRIP, which provides an opportunity for shareholders residing in Canada 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 2023.

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 price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded before the date on which the option is granted. The maximum aggregate number of shares issuable under this plan is 14.7 million shares. As at December 31, 2023, Emera was in compliance with this requirement.

Stock options granted in 2021 and prior vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. Stock options granted in 2022 and thereafter vest in 20 per cent increments on the first, second, third, fourth and fifth 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.

For stock options granted in 2021 and prior, unless a stock option has expired, vested options may be exercised within the 27 months following the option holder's 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. Commencing with the 2022 stock option grant, vested options may be exercised during the full term of the option 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 FV per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

		2023		2022
Weighted average FV per option	**$**	**6.32**	$	5.35
Expected term (1)		**5 years**		5 years
Risk-free interest rate (2)		**3.53 %**		1.79 %
Expected dividend yield (3)		**5.05 %**		4.55 %
Expected volatility (4)		**20.07 %**		18.87 %

(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 2023:

	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, 2022	2,853,879	$ 50.41	1,348,400	$ 4.08
Granted	483,100	54.64	483,100	6.32
Exercised	(146,475)	43.94	N/A	N/A
Forfeited	(94,900)	56.32	(51,625)	3.61
Vested	N/A	N/A	(526,620)	3.58
Options outstanding December 31, 2023	**3,095,604**	**$ 51.20**	**1,253,255**	**$ 5.17**
Options exercisable December 31, 2023 (2)(3)	**1,842,349**	**$ 48.39**		

(1) As at December 31, 2023, there was $5 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 (2022 – $4 million, 3 years).
(2) As at December 31, 2023, the weighted average remaining term of vested options was 5 years with an aggregate intrinsic value of $8 million (2022 – 5 years, $10 million).
(3) As at December 31, 2023, the FV of options that vested in the year was $ 2 million (2022 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2023 was $2 million (2022 – $2 million), which was included in “OM&G” on the Consolidated Statements of Income.

As at December 31, 2023, cash received from option exercises was $6 million (2022 – $9 million). The total intrinsic value of options exercised for the year ended December 31, 2023 was $2 million (2022 – $4 million). The range of exercise prices for the options outstanding as at December 31, 2023 was $32.35 to $60.03 (2022 – $32.35 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 short-term 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 made in cash.

In addition, special DSU awards may be made from time to time by the Management Resources and Compensation Committee (“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, 2023 is presented in the following table:

	Employee DSU	Weighted Average Grant Date FV	Director DSU	Weighted Average Grant Date FV
Outstanding as at December 31, 2022	627,223	$ 41.55	664,258	$ 45.83
Granted including DRIP	85,740	47.66	117,893	49.99
Exercised	N/A	N/A	(53,093)	49.39
Outstanding and exercisable as at December 31, 2023	**712,963**	**$ 42.29**	**729,058**	**$ 46.24**

Compensation cost recovery recognized for employee and director DSU's for the year ended December 31, 2023 was $2 million (2022 – $6 million). Tax expense related to this compensation cost recovery for share units realized for the year ended December 31, 2023 was $1 million (2022 – $2 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for employees was $36 million (2022 – $33 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for directors was $37 million (2022 – $34 million). Cash payments made during the year ended December 31, 2023 associated with the DSU plan were $3 million (2022 – $8 million).

Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the 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. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee PSUs for the year ended December 31, 2023 is presented in the following table:

	Employee PSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2022	690,446	$	56.24	$	40
Granted including DRIP	386,261		52.71		
Exercised	(323,155)		54.62		
Forfeited	(10,187)		55.15		
Outstanding as at December 31, 2023	**743,365**	**$**	**55.13**	**$**	**41**

Compensation cost recognized for the PSU plan for the year ended December 31, 2023 was $11 million (2022 – $18 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $5 million). Cash payments made during the year ended December 31, 2023 associated with the PSU plan were $19 million (2022 – $24 million).

Restricted Share Unit Plan

Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the 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. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee RSUs for the year ended December 31, 2023 is presented in the following table:

	Employee RSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2022	508,468	$	56.25	$	30
Granted including DRIP	236,537		52.07		
Exercised	(171,537)		54.62		
Forfeited	(10,827)		54.76		
Outstanding as at December 31, 2023	**562,641**	**$**	**55.01**	**$**	**32**

Compensation cost recognized for the RSU plan for the year ended December 31, 2023 was $10 million (2022 – $9 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $2 million). Cash payments made during the year ended December 31, 2023 associated with the RSU plan were $10 million (2022– nil).

Variable Interest Entities	12 Months Ended Dec. 31, 2023
Variable Interest Entities [Abstract]	
Variable Interest Entities	

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 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, 2023**		December 31, 2022	
millions of dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 489**	**$ 6**	$ 501	$ 6

Subsequent Events	12 Months Ended Dec. 31, 2023
Subsequent Events [Abstract]	
Subsequent Events	**33. SUBSEQUENT EVENTS** These financial statements and notes reflect the Company’s evaluation of events occurring subsequent to the balance sheet date through February 26, 2024, the date the financial statements were issued.

Summary of Significant Accounting Policies (Policies)	12 Months Ended Dec. 31, 2023
Summary of Significant Accounting Policies [Abstract]	
Basis of Presentation	**Basis of Presentation** These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP") and in the opinion of management, 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 ("CAD"), unless otherwise indicated.
Principles of Consolidation	**Principles of Consolidation** These consolidated financial statements include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. 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 VIE that most significantly impacts its economic performance and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. 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. For further details on VIEs, refer to note 32. 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 PP&E, regulatory assets, regulated fuel for generation and purchased power, or OM&G, depending on the nature of the transaction.
Use of Management Estimates	**Use of Management Estimates** The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations ("ARO"), and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.
Regulatory Matters	**Regulatory Matters** Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. Rates are designed to recover prudently incurred costs of providing 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 6.
Foreign Currency Translation	**Foreign Currency Translation** Monetary assets and liabilities denominated in foreign currencies are converted to CAD 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 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 USD denominated debt held in CAD functional currency companies as hedges of net investments in USD denominated foreign operations. The change in the carrying amount of these investments, measured at exchange rates in effect at the balance sheet date is recorded in Other Comprehensive Income ("OCI").

Revenue Recognition

Revenue Recognition

Regulated Electric and Gas Revenue:
Electric and gas 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 and gas are delivered to customers over time as the customer simultaneously receives and consumes the benefits. Electric and gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity and gas are recognized at rates approved by the respective regulators 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, electricity and gas delivered to customers, but not billed, is estimated and corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the megawatt hours ("MWh") or 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 energy demand, weather, line losses 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 the contract are satisfied and are presented on a net basis reflecting the nature of 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 the terms of the 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.

Franchise Fees and Gross Receipts

Franchise Fees and Gross Receipts

TEC 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 TEC 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.

PP&E

PP&E

PP&E is recorded at original cost, including AFUDC or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units, are included in "PP&E" on the Consolidated Balance Sheets. When units of regulated PP&E 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 PP&E occurs, gains and losses are included in income as the dispositions occur.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, 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 and major maintenance projects that do not increase overall life of the related assets are expensed as incurred. 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 regulatory approval.

Intangible assets, which are included in “PP&E” on the Consolidated Balance Sheets, 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

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated FV 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 (“FX”). Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. 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 a qualitative assessment and determines it is more likely than not that its FV 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 FV of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its FV, an impairment loss is recorded. Management estimates the FV of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach uses a discounted cash flow analysis which relies on management’s best estimate of the reporting unit’s 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. For the market approach, management estimates FV based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the FV of a reporting unit using an income approach include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting unit’s net operating loss (“NOL”) and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera’s reporting units.

As of December 31, 2023, $5,868 million of Emera’s goodwill represents the excess of the acquisition purchase price for TECO Energy (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q4 2023, qualitative assessments were performed for NMGC and PGS given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2022 and Q4 2019, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result, no impairment charges were recognized.

In Q4 2022, as a result of a quantitative assessment, the Company recorded a goodwill impairment charge of $73 million, reducing the GBPC goodwill balance to nil as at December 31, 2022. For further details, refer to note 22.

Income Taxes and Investment Tax Credits

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 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 income tax assets will be recovered from future taxable income is assessed and assumptions are made about the expected timing of reversal of deferred income tax assets and liabilities. If management subsequently determines it is likely that some or all of a deferred income tax asset will not be realized, 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 on regulated assets by TEC, PGS and NMGC are deferred and amortized as required by regulatory practices.

TEC, PGS, NMGC and BLPC 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 regulators. 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 detail, refer to note 10.

Derivatives and Hedging Activities

Derivatives and Hedging Activities

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

The Company recognizes the FV 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 if the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, change in the FV of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Where documentation or effectiveness requirements are not met, the derivatives are recognized at FV with any changes in FV 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 FV 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. TEC has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases that ended on December 31, 2022 and was extended through December 31, 2024 as a result of TEC's 2021 rate case settlement agreement.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in FV 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 non-regulated operating revenues, fuel for generation and purchased power, other expenses, inventory, and OM&G, 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 FV 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".

Lessee, Leases

Leases

The Company determines whether a contract contains a lease at inception by evaluating whether 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 for annual requirements to purchase wind and hydro energy over varying contract lengths which 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 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.

Lessor, Leases

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 FV 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.

Cash, Cash Equivalents and Restricted Cash

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

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 recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Management estimates credit losses related to accounts receivable by 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.

Allowance for Credit Losses

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 recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Management estimates credit losses related to accounts receivable by 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.

Inventory

Inventory

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

Asset Impairment

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 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 FV. 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.

As at December 31, 2023, there are no indications of impairment of Emera's long-lived assets. No impairment charges related to long-lived assets were recognized in 2023 or 2022.

Equity Method Investments:
The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the FV of these investments to their carrying values, if a FV assessment was completed, or by reviewing for the presence of impairment indicators. 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 FV. No impairment of equity method investments was required in either 2023 or 2022.

Financial Assets:
Equity investments, other than those accounted for under the equity method, are measured at FV, with changes in FV recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable FV 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 2023 or 2022.

Asset Retirement Obligations and Cost of Removal

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 FV of 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 that are not recognized in the consolidated financial statements, as the FV of these obligations could not be reasonably estimated, given 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 FV in the period in which an amount can be determined.

Cost of Removal ("COR")

TEC, PGS, NMGC and NSPI recognize non-ARO 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 PP&E 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

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 FV-based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated FV 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 FV and re-measured at FV at each reporting date, with the change in liability recognized in income.

Employee Benefits

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 unamortized gains and losses and past service costs in "AOCI" or "Regulatory assets" on the Consolidated Balance Sheets. 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. For further detail, refer to note 21.

Segment Information (Tables)

Segment Information [Abstract]

Segment Information

12 Months Ended Dec. 31, 2023

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2023							
Operating revenues from external customers (1)	$ 3,548	$ 1,671	$ 1,510	$ 526	$ 308	$ -	$ **7,563**
Inter-segment revenues (1)	8	-	14	-	31	(53)	**-**
Total operating revenues	3,556	1,671	1,524	526	339	(53)	**7,563**
Regulated fuel for generation and purchased power	920	699	-	275	-	(13)	**1,881**
Regulated cost of natural gas	-	-	527	-	-	-	**527**
OM&G	830	384	405	130	151	(21)	**1,879**
Provincial, state and municipal taxes	289	45	91	3	5	-	**433**
Depreciation and amortization	571	276	126	68	8	-	**1,049**
Income from equity investments	-	109	21	4	12	-	**146**
Other income, net	69	32	11	7	20	19	**158**
Interest expense, net (2)	271	170	129	23	332	-	**925**
Income tax expense (recovery)	117	(9)	64	-	(44)	-	**128**
Non-controlling interest in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	66	-	**66**
Net income (loss) attributable to common shareholders	$ 627	$ 247	$ 214	$ 37	$ (147)	$ -	$ **978**
Capital expenditures	$ 1,736	$ 450	$ 664	$ 63	$ 8	$ -	$ **2,921**
As at December 31, 2023							
Total assets	$ 21,119	$ 8,634	$ 7,735	$ 1,311	$ 1,938	$ (1,257)	$ **39,480**
Investments subject to significant influence	$ -	$ 1,236	$ 118	$ 48	$ -	$ -	$ **1,402**
Goodwill	$ 4,628	$ -	$ 1,240	$ -	$ 3	$ -	$ **5,871**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, 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 of $95 million for the year ended December 31, 2023, between the Florida Electric Utility, Gas Utilities and Infrastructure and Other segments.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2022							
Operating revenues from external customers (1)	$ 3,280	$ 1,675	$ 1,697	$ 518	$ 418	$ -	$ **7,588**
Inter-segment revenues (1)	7	-	7	-	22	(36)	**-**
Total operating revenues	3,287	1,675	1,704	518	440	(36)	**7,588**
Regulated fuel for generation and purchased power	1,086	803	-	290	-	(8)	**2,171**
Regulated cost of natural gas	-	-	800	-	-	-	**800**
OM&G	625	338	365	123	156	(11)	**1,596**
Provincial, state and municipal taxes	235	43	83	3	3	-	**367**
Depreciation and amortization	507	259	118	61	7	-	**952**
Income from equity investments	-	87	21	4	17	-	**129**
Other income (expenses), net	68	24	13	-	23	17	**145**
Interest expense, net (2)	185	136	81	19	288	-	**709**
GBPC impairment charge	-	-	-	73	-	-	**73**
Income tax expense (recovery)	121	(8)	70	-	2	-	**185**
Non-controlling interest in subsidiaries	-	-	-	1	-	-	**1**
Preferred stock dividends	-	-	-	-	63	-	**63**
Net income (loss) attributable to common shareholders	$ 596	$ 215	$ 221	$ (48)	$ (39)	$ -	$ **945**
Capital expenditures	$ 1,425	$ 507	$ 574	$ 63	$ 6	$ -	$ **2,575**
As at December 31, 2022							
Total assets	$ 21,053	$ 8,223	$ 7,737	$ 1,337	$ 2,835	$ (1,443)	$ **39,742**
Investments subject to significant influence	$ -	$ 1,241	$ 128	$ 49	$ -	$ -	$ **1,418**
Goodwill	$ 4,739	$ -	$ 1,270	$ -	$ 3	$ -	$ **6,012**

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, 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 of $13 million for the year ended December 31, 2022, between the Gas Utilities and Infrastructure and Other segments.

Geographical Information

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

For the millions of dollars	Year ended December 31 **2023**	 2022
United States	**5,310**	$ 5,346
Canada	**1,727**	1,725
Barbados	**389**	384
The Bahamas	**137**	122
Dominica	**-**	11
	$ 7,563	$ 7,588

Property Plant and Equipment:

As at millions of dollars	**December 31** **2023**	December 31 2022
United States	**$ 18,588**	$ 17,382
Canada	**4,878**	4,689
Barbados	**576**	583
The Bahamas	**334**	342
	$ 24,376	$ 22,996

Revenue (Tables)

Revenue [Abstract]

Disaggregation of Revenue by Major Source

12 Months Ended Dec. 31, 2023

millions of dollars	Electric Florida Electric Utility	Electric Canadian Electric Utilities	Electric Other Electric Utilities	Gas Gas Utilities and Infrastructure	Other	Other Inter-Segment Eliminations	Total
For the year ended December 31, 2023							
Regulated Revenue							
Residential	$ 2,307	$ 910	$ 183	$ 724	$ -	$ -	$ 4,124
Commercial	1,083	463	285	425	-	-	2,256
Industrial	274	219	33	93	-	(13)	606
Other electric	395	41	7	-	-	-	443
Regulatory deferrals	(522)	-	12	-	-	-	(510)
Other (1)	19	38	6	199	-	(8)	254
Finance income (2)(3)	-	-	-	62	-		62
Regulated revenue	$ 3,556	$ 1,671	$ 526	$ 1,503	$ -	$ (21)	$ 7,235
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	96	-	96
Other non-regulated operating revenue	-	-	-	21	27	(23)	25
Mark-to-market (3)	-	-	-	-	216	(9)	207
Non-regulated revenue	$ -	$ -	$ -	$ 21	$ 339	$ (32)	$ 328
Total operating revenues	**$ 3,556**	**$ 1,671**	**$ 526**	**$ 1,524**	**$ 339**	**$ (53)**	**$ 7,563**
For the year ended December 31, 2022							
Regulated Revenue							
Residential	$ 1,799	$ 834	$ 184	$ 800	$ -	$ -	**$** 3,617
Commercial	869	427	282	461	-	-	2,039
Industrial	230	353	32	83	-	(7)	691
Other electric	398	28	6	-	-	-	432
Regulatory deferrals	(27)	-	6	-	-	-	(21)
Other (1)	18	33	8	283	-	(7)	335
Finance income (2)(3)	-	-	-	61	-	-	61
Regulated revenue	$ 3,287	$ 1,675	$ 518	$ 1,688	$ -	$ (14)	7,154
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	143	-	143
Other non-regulated operating revenue	-	-	-	16	16	(10)	22
Mark-to-market (3)	-	-	-	-	281	(12)	269
Non-regulated revenue	$ -	$ -	$ -	$ 16	$ 440	$ (22)	434
Total operating revenues	$ 3,287	$ 1,675	$ 518	$ 1,704	$ 440	$ (36)	$ 7,588

(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.

Regulatory Assets and Liabilities (Tables)	12 Months Ended Dec. 31, 2023
Regulatory Assets and Liabilities [Abstract]	
Regulatory Assets	

As at millions of dollars		**December 31 2023**		December 31 2022
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,233**	$	1,166
TEC capital cost recovery for early retired assets		**671**		674
NSPI FAM		**395**		307
Pension and post-retirement medical plan		**364**		369
Cost recovery clauses		**151**		707
Deferrals related to derivative instruments		**88**		30
Storm cost recovery clauses		**52**		138
Environmental remediations		**26**		27
Stranded cost recovery		**25**		27
NMGC winter event gas cost recovery		**-**		69
Other		**100**		106
	$	**3,105**	$	3,620
Current	**$**	**339**	$	602
Long-term		**2,766**		3,018
Total regulatory assets	**$**	**3,105**	$	3,620
Regulatory liabilities				
Accumulated reserve – COR		**849**		895
Deferred income tax regulatory liabilities		**830**		877
Cost recovery clauses		**32**		70
BLPC Self-insurance fund ("SIF") (note 32)		**29**		30
Deferrals related to derivative instruments		**17**		230
NMGC gas hedge settlements (note 18)		**-**		162
Other		**15**		9
	$	**1,772**	$	2,273
Current	**$**	**168**	$	495
Long-term		**1,604**		1,778
Total regulatory liabilities	**$**	**1,772**	$	2,273

Regulatory Liabilities

As at millions of dollars		**December 31 2023**		December 31 2022
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,233**	$	1,166
TEC capital cost recovery for early retired assets		**671**		674
NSPI FAM		**395**		307
Pension and post-retirement medical plan		**364**		369
Cost recovery clauses		**151**		707
Deferrals related to derivative instruments		**88**		30
Storm cost recovery clauses		**52**		138
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NMGC winter event gas cost recovery		**-**		69
Other		**100**		106
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NMGC gas hedge settlements (note 18)		**-**		162
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Current	**$**	**168**	$	495
Long-term		**1,604**		1,778
Total regulatory liabilities	**$**	**1,772**	$	2,273

Investments Subject to Significant Influence and Equity Income (Tables)	12 Months Ended
	Dec. 31, 2023
Variable Interest Entity [Line Items]	
Summary of Investments Subject to Significant Influence	(see table below)

millions of dollars	Carrying Value As at December 31 2023	2022	Equity Income For the year ended December 31 2023	2022	Percentage of Ownership 2023
LIL (1)	**$ 747**	$ 740	**$ 63**	$ 58	**31.0**
NSPML	**489**	501	**46**	29	**100.0**
M&NP (2)	**118**	128	**21**	21	**12.9**
Lucelec (2)	**48**	49	**4**	4	**19.5**
Bear Swamp (3)	**-**	-	**12**	17	**50.0**
	$ 1,402	$ 1,418	**$ 146**	$ 129	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.5 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) Emera has significant influence over the operating and financial decisions of these companies through Board representation and therefore, 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 $81 million (2022 – $95 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

NSP Maritime Link Inc. [Member]

Variable Interest Entity [Line Items]

Summary of Investments Subject to Significant Influence

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 dollars	December 31 2023	2022
Balance Sheets		
Current assets	**$ 21**	$ 17
PP&E	**1,473**	1,517
Regulatory assets	**272**	265
Non-current assets	**29**	29
Total assets	**$ 1,795**	$ 1,828
Current liabilities	**$ 48**	$ 48
Long-term debt (1)	**1,109**	1,149
Non-current liabilities	**149**	130
Equity	**489**	501
Total liabilities and equity	**$ 1,795**	$ 1,828

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

Other Income, Net (Tables)	12 Months Ended Dec. 31, 2023

Other Income, Net [Abstract]

Components of Other Expense, Net

For the millions of dollars	Year ended December 31 2023	2022
Interest income	**$ 43**	$ 25
AFUDC	**38**	52
Pension non-current service cost recovery	**35**	24
FX gains (losses)	**20**	(26)
TECO Guatemala Holdings award (1)	**-**	63
Other	**22**	7
	$ 158	$ 145

(1) On December 15, 2022, a payment of $63 million was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment in TGH, a wholly-owned subsidiary of TECO Energy.

Interest Expense, Net (Tables)	12 Months Ended Dec. 31, 2023
Interest Expense, Net [Abstract]	
Components of Interest Expense, Net	Interest expense, net consisted of the following:

For the millions of Canadian dollars	Year ended December 31			
		2023		2022
Interest on debt	**$**	**954**	$	727
Allowance for borrowed funds used during construction		**(16)**		(21)
Other		**(13)**		3
	$	**925**	$	709

Income Taxes (Tables)	12 Months Ended Dec. 31, 2023
Income Taxes [Abstract]	
Reconciliation of Effective Income Tax Rate	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 dollars		2023		2022
Income before provision for income taxes	**$**	**1,173**	$	1,194
Statutory income tax rate		**29.0%**		29.0%
Income taxes, at statutory income tax rate		**340**		346
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		**(72)**		(70)
Tax credits		**(53)**		(18)
Foreign tax rate variance		**(36)**		(44)
Amortization of deferred income tax regulatory liabilities		**(33)**		(33)
Tax effect of equity earnings		**(15)**		(10)
GBPC impairment charge		**-**		21
Other		**(3)**		(7)
Income tax expense	**$**	**128**	$	185
Effective income tax rate		**11%**		15%

Composition of Taxes on Income from Continuing Operations

millions of dollars		2023		2022
Current income taxes				
Canada	**$**	**26**	$	25
United States		**5**		8
Deferred income taxes				
Canada		**93**		122
United States		**128**		252
Investment tax credits				
United States		**(29)**		(7)
Operating loss carryforwards				
Canada		**(93)**		(94)
United States		**(2)**		(121)
Income tax expense	**$**	**128**	$	185

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 dollars		2023		2022
Canada	**$**	**171**	$	173
United States		**964**		1,063
Other		**38**		(42)
Income before provision for income taxes	**$**	**1,173**	$	1,194

Schedule of Deferred Income Tax Assets and Liabilities

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

millions of dollars		2023		2022
Deferred income tax assets:				
Tax loss carryforwards	**$**	**1,195**	$	1,207
Tax credit carryforwards		**454**		415
Derivative instruments		**205**		45
Regulatory liabilities		**175**		264
Other		**372**		341
Total deferred income tax assets before valuation allowance		**2,401**		2,272
Valuation allowance		**(363)**		(312)
Total deferred income tax assets after valuation allowance	**$**	**2,038**	$	1,960
Deferred income tax (liabilities):				
PP&E	**$**	**(3,223)**	$	(2,981)
Derivative instruments		**(235)**		(125)
Investments subject to significant influence		**(216)**		(181)
Regulatory assets		**(196)**		(310)
Other		**(312)**		(322)
Total deferred income tax liabilities	**$**	**(4,182)**	$	(3,919)
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets	**$**	**208**	$	237
Long-term deferred income tax liabilities		**(2,352)**		(2,196)
Net deferred income tax liabilities	**$**	**(2,144)**	$	(1,959)

Net Operating Loss ("NOL"), Capital Loss and Tax Credit Carryforwards and Their Expiration Periods

Emera's NOL, capital loss and tax credit carryforwards and their expiration periods as at December 31, 2023 consisted of the following:

millions of dollars	Tax Carryforwards	Subject to Valuation Allowance	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 2,914	$ (1,164)	$ 1,750	2026 - 2043
Capital loss	73	(73)	-	Indefinite
United States				
Federal NOL	$ 1,360	$ (1)	$ 1,359	2036 - Indefinite
State NOL	1,003	(1)	1,002	2026 - Indefinite
Tax credit	454	(3)	451	2025 - 2043
Other				
NOL	$ 81	$ (28)	$ 53	2024 - 2030

Details of Change in Unrecognized Tax Benefits

millions of dollars	**2023**	2022
Balance, January 1	**$ 33**	$ 28
Increases due to tax positions related to current year	**5**	5
Increases due to tax positions related to a prior year	**1**	2
Decreases due to tax positions related to a prior year	**(2)**	(2)
Balance, December 31	**$ 37**	$ 33

Common Stock (Tables)	12 Months Ended Dec. 31, 2023

Common Stock [Abstract]

Summary of Issued and Outstanding Common Stock

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

Issued and outstanding:	2023 millions of shares		2023 millions of dollars	2022 millions of shares		2022 millions of dollars
Balance, January 1	**269.95**	**$**	**7,762**	261.07	$	7,242
Issuance of common stock under ATM program (1)(2)	**8.29**		**397**	4.07		248
Issued under the DRIP, net of discounts	**5.26**		**272**	4.21		238
Senior management stock options exercised and Employee Share Purchase Plan	**0.62**		**31**	0.60		34
Balance, December 31	**284.12**	**$**	**8,462**	269.95	$	7,762

(1) For the year ended December 31, 2022, a total of 4,072,469 common shares were issued under Emera's ATM program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs).
(2) For the year ended December 31, 2023, a total of 8,287,037 common shares were issued under Emera's ATM program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs).

Earnings Per Share (Tables)	12 Months Ended Dec. 31, 2023
Earnings Per Share [Abstract]	
Computation of Basic and Diluted Earnings per Share	The following table reconciles the computation of basic and diluted earnings per share:

For the millions of dollars (except per share amounts)	Year ended December 31 **2023**	 2022
Numerator		
Net income attributable to common shareholders	**$ 977.7**	$ 945.1
Diluted numerator	**977.7**	945.1
Denominator		
Weighted average shares of common stock outstanding – basic	**273.6**	265.5
Stock-based compensation	**0.2**	0.4
Weighted average shares of common stock outstanding – diluted	**273.8**	265.9
Earnings per common share		
Basic	**$ 3.57**	$ 3.56
Diluted	**$ 3.57**	$ 3.55

Accumulated Other Comprehensive Income (Tables)	12 Months Ended
	Dec. 31, 2023
Accumulated Other Comprehensive Income [Abstract]	
Components of Accumulated Other Comprehensive Income	The components of AOCI are as follows:

millions of dollars		Unrealized (loss) gain on translation of self-sustaining foreign operations		Net change in net investment hedges		Losses 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, 2023												
Balance, January 1, 2023	**$**	**639**	**$**	**(62)**	**$**	**16**	**$**	**(2)**	**$**	**(13)**	**$**	**578**
Other comprehensive (loss) income before reclassifications		**(270)**		**38**		**-**		**-**		**-**		**(232)**
Amounts reclassified from AOCI		**-**		**-**		**(2)**		**-**		**(39)**		**(41)**
Net current period other comprehensive (loss) income		**(270)**		**38**		**(2)**		**-**		**(39)**		**(273)**
Balance, December 31, 2023	**$**	**369**	**$**	**(24)**	**$**	**14**	**$**	**(2)**	**$**	**(52)**	**$**	**305**
For the year ended December 31, 2022												
Balance, January 1, 2022	$	10	$	35	$	18	$	(1)	$	(37)	$	25
Other comprehensive income (loss) before reclassifications		629		(97)		-		(1)		-		531
Amounts reclassified from AOCI		-		-		(2)		-		24		22
Net current period other comprehensive income (loss)		629		(97)		(2)		(1)		24		553
Balance, December 31, 2022	$	639	$	(62)	$	16	$	(2)	$	(13)	$	578

Reclassifications out of Accumulated Other Comprehensive Income (Loss)

The reclassifications out of AOCI are as follows:

For the millions of dollars	Affected line item in the Consolidated Financial Statements		Year ended December 31 **2023**		2022
Gains on derivatives recognized as cash flow hedges					
Interest rate hedge	Interest expense, net	**$**	**(2)**	$	(2)
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses	Other income, net	**$**	**-**	$	10
Past service costs	Other income, net		**2**		-
Amounts reclassified into obligations	Pension and post-retirement benefits		**(40)**		15
Total before tax			**(38)**		25
Income tax expense			**(1)**		(1)
Total net of tax		**$**	**(39)**	$	24
Total reclassifications out of AOCI, net of tax, for the period		**$**	**(41)**	$	22

Inventory (Tables)	12 Months Ended Dec. 31, 2023

Inventory [Abstract]

Components of Inventory

As at	December 31	December 31
millions of dollars	2023	2022
Fuel	$ 382	$ 404
Materials	408	365
Total	$ 790	$ 769

Derivative Instruments (Tables)

Derivative Instruments (Tables)	12 Months Ended Dec. 31, 2023

Derivative Instruments

Derivative Assets and Liabilities

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

As at millions of dollars	Derivative Assets **December 31 2023**	Derivative Assets December 31 2022	Derivative Liabilities **December 31 2023**	Derivative Liabilities December 31 2022
Regulatory deferral:				
Commodity swaps and forwards	**$ 16**	$ 186	**$ 76**	$ 42
FX forwards	**3**	18	**3**	1
Physical natural gas purchases and sales	**-**	52	**-**	-
	19	256	**79**	43
HFT derivatives:				
Power swaps and physical contracts	**29**	89	**36**	77
Natural gas swaps, futures, forwards, physical contracts	**319**	340	**531**	1,224
	348	429	**567**	1,301
Other derivatives:				
Equity derivatives	**4**	-	**-**	5
FX forwards	**18**	5	**7**	23
	22	5	**7**	28
Total gross current derivatives	**389**	690	**653**	1,372
Impact of master netting agreements:				
Regulatory deferral	**(3)**	(18)	**(3)**	(18)
HFT derivatives	**(146)**	(276)	**(146)**	(276)
Total impact of master netting agreements	**(149)**	(294)	**(149)**	(294)
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078
Current (1)	**174**	296	**386**	888
Long-term (1)	**66**	100	**118**	190
Total derivatives	**$ 240**	$ 396	**$ 504**	$ 1,078

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

Cash Flow Hedges Recorded in AOCI

For the millions of dollars	Year ended December 31 **2023** **Interest rate hedge**	Year ended December 31 2022 Interest rate hedge
Realized gain in interest expense, net	**$ 2**	$ 2
Total gains in net income	**$ 2**	$ 2

As at millions of dollars	**December 31 2023** **Interest rate hedge**	December 31 2022 Interest rate hedge
Total unrealized gain in AOCI – effective portion, net of tax	**$ 14**	$ 16

Changes in Realized and Unrealized Gains (Losses) on Derivatives

millions of dollars For the year ended December 31	**Physical natural gas purchases**	**Commodity swaps and forwards**	**FX forwards** **2023**	Physical natural gas purchases	Commodity swaps and forwards	FX forwards 2022
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (109)**	**$ (3)**	$ -	$ (69)	$ 1
Unrealized gain (loss) in regulatory liabilities	**(3)**	**(73)**	**-**	28	343	16
Realized (gain) loss in regulatory assets	**-**	**(5)**	**-**	-	48	-
Realized (gain) loss in regulatory liabilities	**-**	**2**	**-**	-	(41)	-
Realized (gain) loss in inventory (1)	**-**	**4**	**(10)**	-	(121)	1
Realized (gain) in regulated fuel for generation and purchased power (2)	**(49)**	**(9)**	**(4)**	(64)	(146)	**-**
Other	**-**	**(14)**	**-**	-	-	-
Total change in derivative instruments	**$ (52)**	**$ (204)**	**$ (17)**	$ (36)	$ 14	$ 18

(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 dollars	Year ended December 31 **2023**	Year ended December 31 2022
Power swaps and physical contracts in non-regulated operating revenues	**$ (6)**	$ 17
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**1,043**	47
Total gains in net income	**$ 1,037**	$ 64

For the millions of dollars	Year ended December 31			
	2023		2022	
	FX Forwards	**Equity Derivatives**	FX Forwards	Equity Derivatives
Unrealized gain (loss) in OM&G	**$ -**	**$ 4**	$ -	$ (5)
Unrealized gain (loss) in other income, net	**28**	**-**	(18)	-
Realized loss in OM&G	**-**	**(13)**	-	(17)
Realized loss in other income, net	**(11)**	**-**	(6)	-
Total gains (losses) in net income	**$ 17**	**$ (9)**	$ (24)	$ (22)

Notional Volumes of Outstanding Derivatives

millions	2024	2025-2026
Physical natural gas purchases:		
Natural gas (MMBtu)	7	6
Commodity swaps and forwards purchases:		
Natural gas (MMBtu)	16	10
Power (MWh)	1	1
Coal (metric tonnes)	1	-
FX swaps and forwards:		
FX contracts (millions of USD)	$ 241	$ 70
Weighted average rate	1.3155	1.3197
% of USD requirements	63%	17%

millions	2024	2025	2026	2027	2028 and thereafter
Natural gas purchases (Mmbtu)	296	80	50	38	30
Natural gas sales (Mmbtu)	338	86	16	6	4
Power purchases (MWh)	1	-	-	-	-
Power sales (MWh)	1	-	-	-	-

Summary of Concentration Risk

Concentration Risk

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

As at	**December 31, 2023**		December 31, 2022	
	millions of dollars	**% of total exposure**	millions of dollars	% of total exposure
Receivables, net				
Regulated utilities:				
Residential	**$ 476**	**31%**	$ 455	19%
Commercial	**194**	**13%**	192	8%
Industrial	**84**	**5%**	121	5%
Other	**103**	**7%**	122	5%
Cash collateral	**94**	**6%**	-	0%
	951	**62%**	890	37%
Trading group:				
Credit rating of A- or above	**47**	**3%**	125	5%
Credit rating of BBB- to BBB+	**33**	**2%**	75	3%
Not rated	**108**	**7%**	307	13%
	188	**12%**	507	21%
Other accounts receivable	**151**	**10%**	585	25%
	1,290	**84%**	1,982	83%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**138**	**9%**	202	9%
Credit rating of BBB- to BBB+	**7**	**1%**	8	0%
Not rated	**95**	**6%**	186	8%
	240	**16%**	396	17%
	$ 1,530	**100%**	$ 2,378	100%

Cash Collateral Positions

As at millions of dollars	**December 31 2023**	December 31 2022
Cash collateral provided to others	**$ 101**	$ 224
Cash collateral received from others	**$ 22**	$ 112

FV Measurements (Tables)

12 Months Ended Dec. 31, 2023

FV Measurements [Abstract]

Classification of Fair Value of Derivatives

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2023 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 7	$ 6	$ -	$ 13
FX forwards	-	3	-	3
	7	9	-	16
HFT derivatives:				
Power swaps and physical contracts	(5)	23	-	18
Natural gas swaps, futures, forwards, physical contracts and related transportation	42	108	34	184
	37	131	34	202
Other derivatives:				
FX forwards	-	18	-	18
Equity derivatives	4	-	-	4
	4	18	-	22
Total assets	48	158	34	240
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	43	30	-	73
FX forwards	-	3	-	3
	43	33	-	76
HFT derivatives:				
Power swaps and physical contracts	-	24	-	24
Natural gas swaps, futures, forwards and physical contracts	13	19	365	397
	13	43	365	421
Other derivatives:				
FX forwards	-	7	-	7
	-	7	-	7
Total liabilities	56	83	365	504
Net assets (liabilities)	$ (8)	$ 75	$ (331)	$ (264)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2022 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 120	$ 48	$ -	$ 168
FX forwards	-	18	-	18
Physical natural gas purchases and sales	-	-	52	52
	120	66	52	238
HFT derivatives:				
Power swaps and physical contracts	9	31	4	44
Natural gas swaps, futures, forwards, physical contracts and related transportation	3	72	34	109
	12	103	38	153
Other derivatives:				
FX forwards	-	5	-	5
Total assets	132	174	90	396
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	15	9	-	24
FX forwards	-	1	-	1
	15	10	-	25
HFT derivatives:				
Power swaps and physical contracts	2	28	1	31
Natural gas swaps, futures, forwards and physical contracts	51	118	825	994
	53	146	826	1,025
Other derivatives:				
FX forwards	-	23	-	23
Equity derivatives	5	-	-	5
Total liabilities	73	179	826	1,078
Net assets (liabilities)	$ 59	$ (5)	$ (736)	$ (682)

Change in Fair Value of Level 3 Financial Assets

The change in the FV of the Level 3 financial assets for the year ended December 31, 2023 was as follows:

	Regulatory Deferral	*HFT Derivatives*		
millions of dollars	**Physical natural gas purchases**	**Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 52**	**$ 4**	**$ 34**	**$ 90**
Realized gains (losses) included in fuel for generation and purchased power	**(49)**	**-**	**-**	**(49)**
Unrealized gains (losses) included in regulatory assets and liabilities	**(3)**	**-**	**-**	**(3)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(4)**	**-**	**(4)**
Balance, December 31, 2023	**$ -**	**$ -**	**$ 34**	**$ 34**

Change in Fair Value of Level 3 Financial Liabilities

The change in the FV of the Level 3 financial liabilities for the year ended December 31, 2023 was as follows:

	HFT Derivatives		
millions of dollars	**Power**	**Natural gas**	**Total**
Balance, January 1, 2023	**$ 1**	**$ 825**	**$ 826**
Total realized and unrealized gains included in non-regulated operating revenues	**(1)**	**(460)**	**(461)**
Balance, December 31, 2023	**$ -**	**$ 365**	**$ 365**

Quantitative Information About Significant Unobservable Inputs Used in Level 3 Measurements

millions of dollars	FV Assets	FV Liabilities	Significant Unobservable Input	Low	High	Weighted average (1)
As at December 31, 2023						
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**34**	**365**	Third-party pricing	$1.27	$16.25	$4.85
Total	**$ 34**	**$ 365**				
Net liability		**$ 331**				
As at December 31, 2022						
Regulatory deferral – Physical natural gas purchases	$ 52	$ -	Third-party pricing	$5.79	$31.85	$12.27
HFT derivatives – Power swaps and physical contracts	4	1	Third-party pricing	$43.24	$269.10	$138.79
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	34	825	Third-party pricing	$2.45	$33.88	$12.01
Total	$ 90	$ 826				
Net liability		$ 736				

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

Financial Liabilities not Measured at Fair Value on Consolidated Balance Sheets

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

As at millions of dollars	Carrying Amount	FV	Level 1	Level 2	Level 3	Total
December 31, 2023	**$ 18,365**	**$ 16,621**	**$ -**	**$ 16,363**	**$ 258**	**$ 16,621**
December 31, 2022	$ 16,318	$ 14,670	$ -	$ 14,284	$ 386	$ 14,670

Receivables and Other Current Assets (Tables)	12 Months Ended Dec. 31, 2023
Receivables and Other Current Assets [Abstract]	
Summary of Receivables and Other Current Assets	**18. RECEIVABLES AND OTHER CURRENT ASSETS**

As at millions of dollars		**December 31 2023**		December 31 2022
Customer accounts receivable – billed	**$**	**805**	$	1,096
Capitalized transportation capacity (1)		**358**		781
Customer accounts receivable – unbilled		**363**		424
Prepaid expenses		**105**		82
Income tax receivable		**10**		9
Allowance for credit losses		**(15)**		(17)
NMGC gas hedge settlement receivable (2)		**-**		162
Other		**191**		360
Total receivables and other current assets	**$**	**1,817**	$	2,897

(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.
(2) Offsetting amount is included in regulatory liabilities for NMGC as gas hedges are part of the PGAC. For more information, refer to note 6.

Leases (Tables)	12 Months Ended Dec. 31, 2023
Leases [Abstract]	
Lessee, Operating Leases and Additional Information	(see below)

As at millions of dollars	Classification		December 31 **2023**		December 31 2022
Right-of-use asset	Other long-term assets	**$**	**54**	**$**	58
Lease liabilities					
Current	Other current liabilities		**3**		3
Long-term	Other long-term liabilities		**55**		59
Total lease liabilities		**$**	**58**	**$**	62

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

For the		Year ended December 31 **2023**		2022
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows for operating leases (millions of dollars)	**$**	**8**	$	8
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases (millions of dollars)	**$**	**1**	$	1
Weighted average remaining lease term (years)		**44**		44
Weighted average discount rate- operating leases		**3.93%**		3.98%

Lessee, Future Minimum Lease Payments Under Non-Cancellable Operating Leases

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 dollars		2024		2025		2026		2027		2028		Thereafter		Total
Minimum lease payments	$	6	$	5	$	3	$	3	$	3	$	111	$	131
Less imputed interest														(73)
Total													$	58

Lessor, Direct Finance and Sales-Type Leases

As at millions of dollars		December 31 **2023**		December 31 2022
Total minimum lease payment to be received	**$**	**1,360**	$	1,393
Less: amounts representing estimated executory costs		**(190)**		(205)
Minimum lease payments receivable	**$**	**1,170**	$	1,188
Estimated residual value of leased property (unguaranteed)		**183**		183
Less: Credit loss reserve		**(2)**		-
Less: unearned finance lease income		**(693)**		(733)
Net investment in direct finance and sales-type leases	**$**	**658**	$	638
Principal due within one year (included in "Receivables and other current assets")		**37**		34
Net Investment in direct finance and sales type leases - long-term	**$**	**621**	$	604

Lessor, Future Minimum Lease Payments to be Received

As at December 31, 2023, future minimum lease payments to be received for each of the next five years and in aggregate thereafter were as follows:

millions of dollars		2024		2025		2026		2027		2028		Thereafter		Total
Minimum lease payments to be received	$	97	$	99	$	98	$	97	$	96	$	873	$	1,360
Less: executory costs														(190)
Total													$	1,170

Property, Plant and Equipment (Tables)	12 Months Ended Dec. 31, 2023
Property, Plant and Equipment [Abstract]	
Regulated and Non-Regulated Assets	PP&E consisted of the following regulated and non-regulated assets:

As at millions of dollars	Estimated useful life	December 31 2023	December 31 2022
Generation	3 to 131	**$ 13,500**	$ 13,083
Transmission	10 to 80	**2,835**	2,731
Distribution	4 to 80	**7,417**	6,978
Gas transmission and distribution	6 to 92	**5,536**	5,061
General plant and other (1)	2 to 71	**2,985**	2,723
Total cost		**32,273**	30,576
Less: Accumulated depreciation (1)		**(9,994)**	(9,574)
		22,279	21,002
Construction work in progress (1)		**2,097**	1,994
Net book value		**$ 24,376**	$ 22,996

(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, 2023, SeaCoast's share of plant in service was $27 million USD (2022 – $27 million USD), and accumulated depreciation of $2 million USD (2022 – $1 million USD). 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.

Employee Benefit Plans (Tables)

12 Months Ended Dec. 31, 2023

Employee Benefit Plans [Abstract]

Changes in Benefit Obligation and Plan Assets and Funded Status

For the millions of dollars	2023 Defined benefit pension plans	2023 Non-pension benefit plans	2022 Defined benefit pension plans	2022 Non-pension benefit plans
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")				
Balance, January 1	$ 2,158	$ 243	$ 2,624	$ 318
Service cost	30	3	41	4
Plan participant contributions	6	6	6	6
Interest cost	111	13	80	9
Plan amendments	-	(14)	-	-
Benefits paid	(147)	(29)	(174)	(31)
Actuarial losses (gains)	146	10	(480)	(79)
Settlements and curtailments	(8)	-	(6)	-
FX translation adjustment	(23)	(5)	67	16
Balance, December 31	$ 2,273	$ 227	$ 2,158	$ 243
Change in plan assets				
Balance, January 1	$ 2,163	$ 46	$ 2,702	$ 51
Employer contributions	42	23	45	24
Plan participant contributions	6	6	6	6
Benefits paid	(147)	(29)	(174)	(31)
Actual return on assets, net of expenses	262	3	(489)	(7)
Settlements and curtailments	(8)	-	(6)	-
FX translation adjustment	(20)	(1)	79	3
Balance, December 31	$ 2,298	$ 48	$ 2,163	$ 46
Funded status, end of year	$ 25	$ (179)	$ 5	$ (197)

Plans with PBO/APBO in Excess of Plan Assets and Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets

millions of dollars	2023 Defined benefit pension plans	2023 Non-pension benefit plans	2022 Defined benefit pension plans	2022 Non-pension benefit plans
PBO/APBO	$ 120	$ 205	$ 1,006	$ 221
FV of plan assets	37	-	914	-
Funded status	$ (83)	$ (205)	$ (92)	$ (221)

millions of dollars	2023 Defined benefit pension plans	2022 Defined benefit pension plans
ABO	$ 114	$ 111
FV of plan assets	37	33
Funded status	$ (77)	$ (78)

Amounts Recognized in Consolidated Balance Sheets

As at millions of dollars	December 31 2023 Defined benefit pension plans	December 31 2023 Non-pension benefit plans	December 31 2022 Defined benefit pension plans	December 31 2022 Non-pension benefit plans
Other current liabilities	$ (5)	$ (18)	$ (13)	$ (20)
Long-term liabilities	(78)	(187)	(80)	(201)
Other long-term assets	108	26	98	24
AOCI, net of tax and regulatory assets	385	20	358	22
Less: Deferred income tax (expense) recovery in AOCI	(8)	(1)	(7)	(1)
Net amount recognized	$ 402	$ (160)	$ 356	$ (176)

Amounts Recognized in AOCI and Regulatory Assets

millions of dollars	Regulatory assets	Actuarial (gains) losses	Past service (gains) costs
Defined Benefit Pension Plans			
Balance, January 1, 2023	$ 336	$ 15	$ -
Amortized in current period	(6)	(3)	-
Current year additions	1	41	-
Change in FX rate	(7)	-	-
Balance, December 31, 2023	$ 324	$ 53	$ -
Non-pension benefits plans			
Balance, January 1, 2023	$ 31	$ (10)	$ -
Amortized in current period	2	3	-
Current year reductions	(3)	(1)	(3)
Change in FX rate	(1)	-	1
Balance, December 31, 2023	$ 29	$ (8)	$ (2)

As at millions of dollars	December 2023 Defined benefit pension plans	December 2023 Non-pension benefit plans	December 2022 Defined benefit pension plans	December 2022 Non-pension benefit plans
Actuarial losses (gains)	**$ 53**	**(8)**	$ 15	$ (10)
Past service gains	**-**	**(2)**	-	-
Deferred income tax expense	**8**	**1**	7	1
AOCI, net of tax	**61**	**(9)**	22	(9)
Regulatory assets	**324**	**29**	336	31
AOCI, net of tax and regulatory assets	**$ 385**	**$ 20**	$ 358	$ 22

Net Periodic Benefit Cost

As at millions of dollars	Year ended December 31, 2023 Defined benefit pension plans	2023 Non-pension benefit plans	2022 Defined benefit pension plans	2022 Non-pension benefit plans
Service cost	**$ 30**	**$ 3**	$ 41	$ 4
Interest cost	**111**	**13**	80	9
Expected return on plan assets	**(161)**	**(2)**	(144)	-
Current year amortization of:				
Actuarial losses (gains)	**1**	**(3)**	8	-
Regulatory assets (liability)	**6**	**(2)**	21	2
Settlement, curtailments	**2**	**-**	2	-
Total	**$ (11)**	**$ 9**	$ 8	$ 15

Pension Plan Asset Allocations

Canadian Pension Plans

Asset Class	Target Range at Market		
Short-term securities	0%	to	10%
Fixed income	34%	to	49%
Equities:			
Canadian	7%	to	17%
Non-Canadian	35%	to	59%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average		
Cash and cash equivalents	0%	to	10%
Fixed income	29%	to	49%
Equities	48%	to	68%

Fair Value of Plan Assets

millions of dollars As at	NAV	Level 1	Level 2	Total	Percentage December 31, 2023
Cash and cash equivalents	**$ -**	**$ 40**	**$ -**	**$ 40**	**2 %**
Net in-transits	**-**	**(9)**	**-**	**(9)**	**- %**
Equity securities:					
Canadian equity	**-**	**96**	**-**	**96**	**4 %**
United States equity	**-**	**141**	**-**	**141**	**6 %**
Other equity	**-**	**112**	**-**	**112**	**5 %**
Fixed income securities:					
Government	**-**	**-**	**172**	**172**	**8 %**
Corporate	**-**	**-**	**90**	**90**	**4 %**
Other	**-**	**4**	**5**	**9**	**- %**
Mutual funds	**-**	**50**	**-**	**50**	**2 %**
Other	**-**	**6**	**(1)**	**5**	**- %**
Open-ended investments measured at NAV (1)	**1,006**	**-**	**-**	**1,006**	**44 %**
Common collective trusts measured at NAV (2)	**586**	**-**	**-**	**586**	**25 %**
Total	**$ 1,592**	**$ 440**	**$ 266**	**$ 2,298**	**100 %**

As at					December 31, 2022
Cash and cash equivalents	$ -	$ 70	$ -	$ 70	3 %
Net in-transits	-	(70)	-	(70)	(3)%
Equity securities:					
Canadian equity	-	87	-	87	4 %
United States equity	-	233	-	233	11 %
Other equity	-	186	-	186	8 %
Fixed income securities:					
Government	-	-	104	104	5 %
Corporate	-	-	83	83	4 %
Other	-	3	11	14	1 %
Mutual funds	-	68	-	68	3 %
Other	-	-	(3)	(3)	- %
Open-ended investments measured at NAV (1)	790	-	-	790	36 %
Common collective trusts measured at NAV (2)	601	-	-	601	28 %
Total	$ 1,391	$ 577	$ 195	$ 2,163	100 %

(1) Net asset value ("NAV") investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated at least monthly and the funds honour 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 honour subscription and redemption activity regularly.

Expected Cash Flows for Defined Benefit Pension and Other Post-Retirement Benefit Plans

millions of dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2024	$ 34	$ 19
Expected benefit payments		
2024	172	21
2025	163	21
2026	166	21
2027	171	21
2028	173	20
2029 – 2033	890	95

Assumptions Used in Accounting for Defined Benefit Pension and Other Post-Retirement Benefit Plans

Assumptions:
The following table shows the assumptions that have been used in accounting for DB pension and other post-retirement benefit plans:

		2023		2022
(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	**4.89 %**	**4.89 %**	5.33 %	5.31 %
Discount rate - future service	**4.88 %**	**4.89 %**	5.34 %	5.32 %
Rate of compensation increase	**3.87 %**	**3.85 %**	3.62 %	3.61 %
Health care trend - initial (next year)	**-**	**6.04 %**	-	5.40 %
- ultimate	**-**	**3.76 %**	-	3.77 %
- year ultimate reached		**2043**		2043
Benefit cost for year ended December 31:				
Discount rate - past service	**5.33 %**	**5.31 %**	3.05 %	2.81 %
Discount rate - future service	**5.34 %**	**5.32 %**	3.18 %	2.92 %
Expected long-term return on plan assets	**6.56 %**	**2.16 %**	6.07 %	1.32 %
Rate of compensation increase	**3.62 %**	**3.61 %**	3.31 %	3.29 %
Health care trend - initial (current year)	**-**	**5.40 %**	-	5.09 %
- ultimate	**-**	**3.77 %**	-	3.77 %
- year ultimate reached		**2043**		2042

Actual assumptions used differ by plan.

Goodwill (Tables)	12 Months Ended Dec. 31, 2023
Goodwill [Abstract]	
Change in Goodwill	**22. GOODWILL** The change in goodwill for the year ended December 31 was due to the following:

millions of dollars		**2023**		2022
Balance, January 1	**$**	**6,012**	$	5,696
Change in FX rate		**(141)**		389
GBPC impairment charge		**-**		(73)
Balance, December 31	**$**	**5,871**	$	6,012

Short-Term Debt (Tables)

12 Months Ended Dec. 31, 2023

Short-Term Debt [Abstract]

Short-Term Debt and Related Weighted-Average Interest Rates

millions of dollars		2023	Weighted average interest rate		2022	Weighted average interest rate
TEC						
Advances on revolving credit facilities	$	277	5.68 %	$	1,380	5.00 %
Emera						
Non-revolving term facilities		796	6.07 %		796	5.19 %
Bank indebtedness		9	- %		-	- %
TECO Finance						
Advances on revolving credit and term facilities		245	6.54 %		481	5.47 %
PGS						
Advances on revolving credit facilities		73	6.36 %		-	- %
NMGC						
Advances on revolving credit facilities		25	6.46 %		59	5.15 %
GBPC						
Advances on revolving credit facilities		8	5.54 %		10	5.25 %
Short-term debt	$	1,433		$	2,726	

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 dollars	Maturity		2023		2022
TEC - Unsecured committed revolving credit facility	2026	$	401	$	1,084
TECO Energy/TECO Finance - revolving credit facility	2026		-		542
TECO Finance - Unsecured committed revolving credit facility	2026		529		-
Emera - Unsecured non-revolving term facility	2024		400		400
Emera - Unsecured non-revolving term facility	2024		400		400
PGS - Unsecured revolving credit facility	2028		331		-
TEC - Unsecured revolving facility	2024		265		542
TEC - Unsecured revolving facility	2024		265		-
NMGC - Unsecured revolving credit facility	2026		165		169
Other - Unsecured committed revolving credit facilities	Various		17		18
Total		$	2,773	$	3,155
Less:					
Advances under revolving credit and term facilities			1,433		2,731
Letters of credit issued within the credit facilities			3		4
Total advances under available facilities			1,436		2,735
Available capacity under existing agreements		$	1,337	$	420

Other Current Liabilities (Tables)	12 Months Ended Dec. 31, 2023
Other Current Liabilities	
Components of Other Current Liabilities	

As at millions of dollars	**December 31 2023**	December 31 2022
Accrued charges	**$ 172**	$ 174
Nova Scotia Cap-and-Trade Program provision (note 6)	**-**	172
Accrued interest on long-term debt	**107**	97
Pension and post-retirement liabilities (note 21)	**23**	33
Sales and other taxes payable	**11**	14
Income tax payable	**2**	9
Other	**112**	80
	$ 427	$ 579

Long-Term Debt (Tables)

12 Months Ended Dec. 31, 2023

Long-term Debt [Abstract]

Summary of Long-Term Debt, Revolving Credit Facilities, Outstanding Borrowings and Available Capacity

millions of dollars	Weighted average interest rate (1) 2023	2022	Maturity		2023		2022
Emera							
Bankers acceptances, SOFR loans	Variable	Variable	2027	$	**465**	$	403
Unsecured fixed rate notes	4.84%	2.90%	2030		**500**		500
Fixed to floating subordinated notes (2)	6.75%	6.75%	2076		**1,587**		1,625
				$	**2,552**	$	2,528
Emera Finance							
Unsecured senior notes	3.65%	3.65%	2024 - 2046	$	**3,637**	$	3,725
TEC (3)							
Fixed rate notes and bonds	4.61%	4.15%	2024 - 2051	$	**5,654**	$	4,341
PGS							
Fixed rate notes and bonds	5.63%	3.78%	2028 - 2053	$	**1,223**	$	772
NMGC							
Fixed rate notes and bonds	3.78%	3.11%	2026 - 2051	$	**642**	$	521
Non-revolving term facility, floating rate	Variable	Variable	2024		**30**		108
				$	**672**	$	629
NMGI							
Fixed rate notes and bonds	3.64%	3.64%	2024	$	**198**	$	203
NSPI							
Discount Notes (4)	Variable	Variable	2024 - 2027	$	**721**	$	881
Medium term fixed rate notes	5.13%	5.14%	2025 - 2097		**3,165**		2,665
				$	**3,886**	$	3,546
EBP							
Senior secured credit facility	Variable	Variable	2026	$	**246**	$	249
ECI							
Secured senior notes	Variable	Variable	2027	$	**75**	$	86
Amortizing fixed rate notes	4.00%	3.97%	2026		**79**		100
Non-revolving term facility, floating rate	Variable	Variable	2025		**29**		30
Non-revolving term facility, fixed rate	2.15%	2.05%	2025 - 2027		**155**		91
Secured fixed rate senior notes (5)	3.09%	3.06%	2024 - 2029		**84**		142
				$	**422**	$	449
Adjustments							
Fair market value adjustment - TECO Energy acquisition				$	**-**	$	2
Debt issuance costs					**(125)**		(126)
Amount due within one year					**(676)**		(574)
				$	**(801)**	$	(698)
Long-Term Debt				$	**17,689**	$	15,744

(1) Weighted average interest rate of fixed rate long-term debt.
(2) In 2023, the Company recognized $109 million in interest expense (2022 – $110 million) related to its fixed to floating subordinated notes.
(3) A substantial part of TEC's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under TEC's first mortgage bond indenture.
(4) Discount notes are backed by a revolving credit facility which matures in 2027. Banker's acceptances are issued under NSPI's non-revolving term facility which matures in 2024. NSPI has the intention and unencumbered ability to refinance bankers' acceptances for a period of greater than one year.
(5) Notes are issued and payable in either USD or BBD.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of dollars	Maturity		2023		2022
Emera – revolving credit facility (1)	June 2027	$	**900**	$	900
TEC - Unsecured committed revolving credit facility	December 2026		**657**		-
NSPI - revolving credit facility (1)	December 2027		**800**		800
NSPI - non-revolving credit facility	July 2024		**400**		400
Emera - Unsecured non-revolving credit facility	February 2024		**400**		-
NMGC - Unsecured non-revolving credit facility	March 2024		**30**		108
ECI – revolving credit facilities	October 2024		**10**		11
Total		$	**3,197**	$	2,219
Less:					
Borrowings under credit facilities			**1,884**		1,396
Letters of credit issued inside credit facilities			**6**		12
Use of available facilities		$	**1,890**	$	1,408
Available capacity under existing agreements		$	**1,307**	$	811

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million.

	Financial Covenant	**Requirement**	**As at December 31, 2023**
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.57 : 1

Long-Term Debt Maturities

millions of dollars	2024	2025	2026	2027	2028	Thereafter	Total
Emera	$ 199	$ -	$ 1,587	$ 266	$ -	$ 500	$ 2,552
Emera US Finance LP	397	-	992	-	-	2,248	3,637
TEC	397	-	-	-	-	5,257	5,654
PGS	-	-	-	-	463	760	1,223
NMGC	30	-	93	-	-	549	672
NMGI	198	-	-	-	-	-	198
NSPI	398	125	40	323	-	3,000	3,886
EBP	-	-	246	-	-	-	246
ECI	51	139	89	77	62	4	422
Total	$ 1,670	$ 264	$ 3,047	$ 666	$ 525	$ 12,318	$ 18,490

Asset Retirement Obligations (Tables)	12 Months Ended Dec. 31, 2023
Asset Retirement Obligations [Abstract]	
Change in Asset Retirement Obligations	The change in ARO for the years ended December 31 is as follows:

millions of dollars		**2023**		2022
Balance, January 1	**$**	**174**	$	174
Accretion included in depreciation expense		**9**		9
Change in FX rate		**(1)**		3
Additions		**-**		1
Accretion deferred to regulatory asset (included in PP&E)		**18**		1
Liabilities settled		**(8)**		(1)
Revisions in estimated cash flows		**-**		(13)
Balance, December 31	**$**	**192**	$	174

Commitments and Contingencies (Tables)	12 Months Ended Dec. 31, 2023
Commitments and Contingencies Disclosure [Abstract]	
Summary of Contractual Commitments	

millions of dollars	2024	2025	2026	2027	2028	Thereafter	Total
Transportation (1)	$ 696	$ 495	$ 405	$ 388	$ 338	$ 2,597	$ 4,919
Purchased power (2)	274	249	263	312	312	3,435	4,845
Fuel, gas supply and storage	556	215	62	-	5	-	838
Capital projects	778	111	70	1	-	-	960
Equity investment commitments (3)	240	-	-	-	-	-	240
Other	154	147	56	46	35	221	659
	$ 2,698	$ 1,217	$ 856	$ 747	$ 690	$ 6,253	$ 12,461

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $134 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) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

Cumulative Preferred Stock (Tables)	12 Months Ended Dec. 31, 2023
Cumulative Preferred Stock [Abstract]	
Summary of Cumulative Preferred Stock	

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

	Annual Dividend Per Share	Redemption Price per share	**December 31, 2023** Issued and Outstanding	**December 31, 2023** Net Proceeds	December 31, 2022 Issued and Outstanding	December 31, 2022 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	$ 1.6085	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 25.00	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0505	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Series H	$ 1.5810	$ 25.00	**12,000,000**	**$ 295**	12,000,000	$ 295
Series J	$ 1.0625	$ 25.00	**8,000,000**	**$ 196**	8,000,000	$ 196
Series L	$ 1.1500	$ 26.00	**9,000,000**	**$ 222**	9,000,000	$ 222
Total			**58,000,000**	**$ 1,422**	58,000,000	$ 1,422

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 (5)(6)	4.100	1.6085	2.65	August 15, 2028	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 (5)(7)	4.900	1.5810	4.90	August 15, 2028	25.00	Series I
Series J	4.250	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate						
Series E (8)	4.500	1.1250			25.00	
Series L (9)	4.600	1.1500		November 15, 2026	26.00	

(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, 2028, February 15, 2025 and August 15, 2028, 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) On July 6, 2023, Emera announced it would not redeem the outstanding Preferred Shares, Series C and Series H on August 15, 2023. On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C Shares were converted into Series D Shares and no Series H Shares were converted into Series I shares.

(6) The annual fixed dividend per share for Series C Shares was reset from $1.1802 to $1.6085 for the five-year period from and including August 15, 2028.

(7) The annual fixed dividend per share for Series H Shares was reset from $1.2250 to $1.5810 for the five-year period from and including August 15, 2028.

(8) First Preferred Shares, Series E are redeemable at $25.00 per share.

(9) 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.

Non-Controlling Interest in Subsidiaries (Tables)	12 Months Ended Dec. 31, 2023
Non-Controlling Interest in Subsidiaries [Abstract]	
Components of Non-Controlling Interest	**29. NON-CONTROLLING INTEREST IN SUBSIDIARIES**
Preferred Shares of GBPC	**Preferred shares of GBPC:**

29. NON-CONTROLLING INTEREST IN SUBSIDIARIES

As at millions of dollars	**December 31 2023**	December 31 2022
Preferred shares of GBPC	**$ 14**	$ 14
	$ 14	$ 14

Preferred shares of GBPC:

Authorized:

10,000 non-voting cumulative redeemable variable perpetual preferred shares.

	2023		2022	
Issued and outstanding:	**number of shares**	**millions of dollars**	number of shares	millions of dollars
Outstanding as at December 31	**10,000**	**$ 14**	10,000	$ 14

Supplementary Information to Consolidated Statements of Cash Flows (Tables)	12 Months Ended Dec. 31, 2023
Supplementary Information to Consolidated Statements of Cash Flows [Abstract]	
Summary of Supplementary Information to Consolidated Statement of Cash Flows	

For the millions of dollars		Year ended December 31 2023		2022
Changes in non-cash working capital:				
Inventory	**$**	**(31)**	$	(214)
Receivables and other current assets (1)		**653**		(636)
Accounts payable		**(538)**		423
Other current liabilities (2)		**(179)**		193
Total non-cash working capital	**$**	**(95)**	$	(234)

(1) Includes $162 million related to the January 2023 settlement of NMGC gas hedges (2022 – ($162) million). Offsetting regulatory liability is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
(2) Includes ($166) million related to the Nova Scotia Cap-and-Trade program (2022 – $172 million). For further detail, refer to note 6. Offsetting regulatory asset (FAM) balance is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.

For the millions of dollars		Year ended December 31 2023		2022
Supplemental disclosure of cash paid:				
Interest	**$**	**930**	$	699
Income taxes	**$**	**43**	$	67
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**271**	$	237
Decrease in accrued capital expenditures	**$**	**(19)**	$	(13)
Reclassification of short-term debt to long-term debt	**$**	**657**	$	-
Reclassification of long-term debt to short-term debt	**$**	**-**	$	500
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	**$**	**123**	$	(157)

Stock Based Compensation (Tables)	12 Months Ended Dec. 31, 2023
Stock-Based Compensation [Abstract]	
Weighted Average Fair Values per Stock Option and Assumptions for Options Granted	see table below
Summary of Stock Option Information	see table below
Summary of Activity Related to Employee and Director Deferred Share Units	see table below
Summary of Activity Related to Employee Performance Share Units	see table below
Summary of Activity Related to Employee Restricted Share Units	see table below

Weighted Average Fair Values per Stock Option and Assumptions for Options Granted

		2023		2022
Weighted average FV per option	**$**	**6.32**	$	5.35
Expected term (1)		**5 years**		5 years
Risk-free interest rate (2)		**3.53 %**		1.79 %
Expected dividend yield (3)		**5.05 %**		4.55 %
Expected volatility (4)		**20.07 %**		18.87 %

(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.

Summary of Stock Option Information

	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, 2022	2,853,879	$	50.41	1,348,400	$	4.08
Granted	483,100		54.64	483,100		6.32
Exercised	(146,475)		43.94	N/A		N/A
Forfeited	(94,900)		56.32	(51,625)		3.61
Vested	N/A		N/A	(526,620)		3.58
Options outstanding December 31, 2023	**3,095,604**	**$**	**51.20**	**1,253,255**	**$**	**5.17**
Options exercisable December 31, 2023 (2)(3)	**1,842,349**	**$**	**48.39**			

(1) As at December 31, 2023, there was $5 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 (2022 – $4 million, 3 years).
(2) As at December 31, 2023, the weighted average remaining term of vested options was 5 years with an aggregate intrinsic value of $8 million (2022 – 5 years, $10 million).
(3) As at December 31, 2023, the FV of options that vested in the year was $ 2 million (2022 – $2 million).

Summary of Activity Related to Employee and Director Deferred Share Units

	Employee DSU		Weighted Average Grant Date FV	Director DSU		Weighted Average Grant Date FV
Outstanding as at December 31, 2022	627,223	$	41.55	664,258	$	45.83
Granted including DRIP	85,740		47.66	117,893		49.99
Exercised	N/A		N/A	(53,093)		49.39
Outstanding and exercisable as at December 31, 2023	**712,963**	**$**	**42.29**	**729,058**	**$**	**46.24**

Summary of Activity Related to Employee Performance Share Units

	Employee PSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2022	690,446	$	56.24	$	40
Granted including DRIP	386,261		52.71		
Exercised	(323,155)		54.62		
Forfeited	(10,187)		55.15		
Outstanding as at December 31, 2023	**743,365**	**$**	**55.13**	**$**	**41**

Summary of Activity Related to Employee Restricted Share Units

	Employee RSU		Weighted Average Grant Date FV		Aggregate intrinsic value
Outstanding as at December 31, 2022	508,468	$	56.25	$	30
Granted including DRIP	236,537		52.07		
Exercised	(171,537)		54.62		
Forfeited	(10,827)		54.76		
Outstanding as at December 31, 2023	**562,641**	**$**	**55.01**	**$**	**32**

Variable Interest Entities (Tables)	12 Months Ended Dec. 31, 2023
Variable Interest Entities [Abstract]	
Summary of Material Unconsolidated Variable Interest Entities	(see table below)

As at	**December 31, 2023**		December 31, 2022	
millions of dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 489**	**$ 6**	$ 501	$ 6

Summary of Significant Accounting Policies (Nature of Operations) (Narrative) (Details) $ in Billions	12 Months Ended Dec. 31, 2023 CAD ($) Customers MW km
NSP Maritime Link Inc. | Equity Method Investee | NSP Maritime Link Inc Project	
Nature of operations [Line items]	
100% ownership	100.00%
Labrador-Island Link Limited Partnership | Equity Method Investee	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	31.00%
Maritimes and Northeast Pipeline | Equity Method Investee	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	12.90%
Maritimes and Northeast Pipeline | Operating | Gas Utilities and Infrastructure	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	12.90%
Length Of Pipeline | km	1,400
St. Lucia Electricity Services Limited | Equity Method Investee	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	19.50%
St. Lucia Electricity Services Limited | Operating | Other Electric Utilities	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	19.50%
Bear Swamp Power Company LLC | Equity Method Investee	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	50.00%
Tampa Electric | Operating | Florida Electric Utility	
Nature of operations [Line items]	
Number of Customers	840,000
Nova Scotia Power Inc. | Operating | Canadian Electric Utilities	
Nature of operations [Line items]	
Number of Customers	549,000
Emera Newfoundland and Labrador Holdings Inc. | Operating | Canadian Electric Utilities	
Nature of operations [Line items]	
Public Utilities Property Plant And Equipment Generation Capacity | MW	824
Emera Newfoundland and Labrador Holdings Inc. | Operating | Canadian Electric Utilities | NSP Maritime Link Inc Project	
Nature of operations [Line items]	
100% ownership	100.00%

Emera Newfoundland and Labrador Holdings Inc. | NSP Maritime Link Inc. | Operating | Canadian Electric Utilities	
Nature of operations [Line items]	
Public Utilities, Equipment, Transmission and Distribution | $	$ 1.8
Length Of Pipeline | km	170
Emera Newfoundland and Labrador Holdings Inc. | Labrador-Island Link Limited Partnership | Operating | Canadian Electric Utilities	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	31.00%
Public Utilities, Equipment, Transmission and Distribution | $	$ 3.7
Barbados Light and Power Company Limited | Operating | Other Electric Utilities	
Nature of operations [Line items]	
Number of Customers	134,000
Grand Bahama Power Company Limited | Operating | Other Electric Utilities	
Nature of operations [Line items]	
Number of Customers	19,000
Peoples Gas System Division | Gas Utilities and Infrastructure	
Nature of operations [Line items]	
Number of Customers	490,000
New Mexico Gas Company | Gas Utilities and Infrastructure	
Nature of operations [Line items]	
Number of Customers	540,000
Emera Brunswick Pipeline Company Limited | Gas Utilities and Infrastructure	
Nature of operations [Line items]	
Length Of Pipeline | km	145
Public Utilities, Property, Plant and Equipment, Distribution, Useful Life	25 years
Emera Brunswick Pipeline Company Limited | Operating | Gas Utilities and Infrastructure	
Nature of operations [Line items]	
Length Of Pipeline | km	145
Emera Energy | Bear Swamp Power Company LLC | Other	
Nature of operations [Line items]	
Equity Method Investment, Ownership Percentage	50.00%
Public Utilities Property Plant And Equipment Generation Capacity | MW	660
Brooklyn Power Corporation | Operating | Other	
Nature of operations [Line items]	
Public Utilities Property Plant And Equipment Generation Capacity | MW	30

Summary of Significant Accounting Policies (Narrative) (Details)	12 Months Ended				
	Dec. 31, 2023 CAD ($)	Dec. 31, 2022 CAD ($)	Dec. 31, 2022 USD ($)	Dec. 31, 2022 CAD ($)	Dec. 31, 2021 CAD ($)
Asset Impairment Charges					
Impairment charge	$ 0	$ 73,000,000			
Goodwill					
Goodwill	5,871,000,000			$ 6,012,000,000	$ 5,696,000,000
Goodwill impairment charge	$ 0	73,000,000			
Lease, Practical Expedient, Lessor Single Lease Component [true false]	true				
Long-Lived Assets					
Asset Impairment Charges					
Impairment charge	$ 0	0			
Equity Method Investments					
Asset Impairment Charges					
Impairment charge	0	0			
Financial Assets					
Asset Impairment Charges					
Impairment charge	0	0			
TECO Energy					
Goodwill					
Goodwill	5,868,000,000				
GBPC					
Goodwill					
Goodwill					
Goodwill impairment charge		$ 73,000,000			
NMGC					
Goodwill					
Goodwill impairment charge	$ 0				

Dispositions (Narrative) (Details)	Mar. 31, 2022
Dolmec [Member] | Disposition	
Details of the assets and liabilities classified as held for sale [Line items]	
Sale of ownership interest	51.90%

Segment Information (Reportable Segments) (Details) - CAD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2023	Dec. 31, 2022	Dec. 31, 2021
Segment Reporting Information, For the year ended December 31			
Total operating revenues	$ 7,563.0	$ 7,588.0	
OM&G	1,879.0	1,596.0	
Provincial, state and municipal taxes	433.0	367.0	
Depreciation and amortization	1,049.0	952.0	
Income from equity investments	146.0	129.0	
Other income (expenses), net	158.0	145.0	
Interest expense, net	925.0	709.0	
GBPC Impairment charge	0.0	73.0	
Income tax expense (recovery)	128.0	185.0	
Non-controlling interest in subsidiaries	1.0	1.0	
Preferred stock dividends	66.0	63.0	
Net income (loss) attributable to common shareholders	977.7	945.1	
Capital expenditures	2,921.0	2,575.0	
Segment Reporting Information, As at December 31			
Total assets	39,480.0	39,742.0	
Investments subject to significant influence	1,402.0	1,418.0	
Goodwill	5,871.0	6,012.0	$ 5,696.0
Regulated | Electric Revenue			
Segment Reporting Information, For the year ended December 31			
Total operating revenues	5,746.0	5,473.0	
Fuel for generation and purchased power	1,881.0	2,171.0	
Regulated | Natural gas			
Segment Reporting Information, For the year ended December 31			
Total operating revenues	1,489.0	1,681.0	
Fuel for generation and purchased power	527.0	800.0	
Florida Electric Utility			
Segment Reporting Information, For the year ended December 31			
Total operating revenues	3,548.0	3,280.0	
Canadian Electric Utilities			
Segment Reporting Information, For the year ended December 31			
Total operating revenues	1,671.0	1,675.0	
Gas Utilities and Infrastructure			
Segment Reporting Information, For the year ended December 31			
Total operating revenues	1,510.0	1,697.0	
Other Electric Utilities			
Segment Reporting Information, For the year ended December 31			
Total operating revenues	526.0	518.0	
Other			
Segment Reporting Information, For the year ended December 31			

Total operating revenues	308.0	418.0
Operating		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	7,563.0	7,588.0
Operating | Florida Electric Utility		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	3,556.0	3,287.0
OM&G	830.0	625.0
Provincial, state and municipal taxes	289.0	235.0
Depreciation and amortization	571.0	507.0
Income from equity investments	0.0	0.0
Other income (expenses), net	69.0	68.0
Interest expense, net	271.0	185.0
GBPC Impairment charge		0.0
Income tax expense (recovery)	117.0	121.0
Non-controlling interest in subsidiaries	0.0	0.0
Preferred stock dividends	0.0	0.0
Net income (loss) attributable to common shareholders	627.0	596.0
Capital expenditures	1,736.0	1,425.0
Segment Reporting Information, As at December 31		
Total assets	21,119.0	21,053.0
Investments subject to significant influence	0.0	0.0
Goodwill	4,628.0	4,739.0
Operating | Florida Electric Utility | Regulated | Electric Revenue		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	920.0	1,086.0
Operating | Florida Electric Utility | Regulated | Natural gas		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	0.0	0.0
Operating | Canadian Electric Utilities		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	1,671.0	1,675.0
OM&G	384.0	338.0
Provincial, state and municipal taxes	45.0	43.0
Depreciation and amortization	276.0	259.0
Income from equity investments	109.0	87.0
Other income (expenses), net	32.0	24.0
Interest expense, net	170.0	136.0
GBPC Impairment charge		0.0
Income tax expense (recovery)	(9.0)	(8.0)
Non-controlling interest in subsidiaries	0.0	0.0
Preferred stock dividends	0.0	0.0
Net income (loss) attributable to common shareholders	247.0	215.0
Capital expenditures	450.0	507.0

Segment Reporting Information, As at December 31		
Total assets	8,634.0	8,223.0
Investments subject to significant influence	1,236.0	1,241.0
Goodwill	0.0	0.0
Operating | Canadian Electric Utilities | Regulated | Electric Revenue		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	699.0	803.0
Operating | Canadian Electric Utilities | Regulated | Natural gas		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	0.0	0.0
Operating | Gas Utilities and Infrastructure		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	1,524.0	1,704.0
OM&G	405.0	365.0
Provincial, state and municipal taxes	91.0	83.0
Depreciation and amortization	126.0	118.0
Income from equity investments	21.0	21.0
Other income (expenses), net	11.0	13.0
Interest expense, net	129.0	81.0
GBPC Impairment charge		0.0
Income tax expense (recovery)	64.0	70.0
Non-controlling interest in subsidiaries	0.0	0.0
Preferred stock dividends	0.0	0.0
Net income (loss) attributable to common shareholders	214.0	221.0
Capital expenditures	664.0	574.0
Segment Reporting Information, As at December 31		
Total assets	7,735.0	7,737.0
Investments subject to significant influence	118.0	128.0
Goodwill	1,240.0	1,270.0
Operating | Gas Utilities and Infrastructure | Regulated | Electric Revenue		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	0.0	0.0
Operating | Gas Utilities and Infrastructure | Regulated | Natural gas		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	527.0	800.0
Operating | Other Electric Utilities		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	526.0	518.0
OM&G	130.0	123.0
Provincial, state and municipal taxes	3.0	3.0
Depreciation and amortization	68.0	61.0
Income from equity investments	4.0	4.0
Other income (expenses), net	7.0	0.0

Interest expense, net	23.0	19.0
GBPC Impairment charge		73.0
Income tax expense (recovery)	0.0	0.0
Non-controlling interest in subsidiaries	1.0	1.0
Preferred stock dividends	0.0	0.0
Net income (loss) attributable to common shareholders	37.0	(48.0)
Capital expenditures	63.0	63.0
Segment Reporting Information, As at December 31		
Total assets	1,311.0	1,337.0
Investments subject to significant influence	48.0	49.0
Goodwill	0.0	0.0
Operating | Other Electric Utilities | Regulated | Electric Revenue		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	275.0	290.0
Operating | Other Electric Utilities | Regulated | Natural gas		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	0.0	0.0
Operating | Other		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	339.0	440.0
OM&G	151.0	156.0
Provincial, state and municipal taxes	5.0	3.0
Depreciation and amortization	8.0	7.0
Income from equity investments	12.0	17.0
Other income (expenses), net	20.0	23.0
Interest expense, net	332.0	288.0
GBPC Impairment charge		0.0
Income tax expense (recovery)	(44.0)	2.0
Non-controlling interest in subsidiaries	0.0	0.0
Preferred stock dividends	66.0	63.0
Net income (loss) attributable to common shareholders	(147.0)	(39.0)
Capital expenditures	8.0	6.0
Segment Reporting Information, As at December 31		
Total assets	1,938.0	2,835.0
Investments subject to significant influence	0.0	0.0
Goodwill	3.0	3.0
Operating | Other | Regulated | Electric Revenue		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	0.0	0.0
Operating | Other | Regulated | Natural gas		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	0.0	0.0
Intersegment Eliminations		
Segment Reporting Information, For the year ended December 31		

Total operating revenues	(53.0)	(36.0)
OM&G	(21.0)	(11.0)
Provincial, state and municipal taxes	0.0	0.0
Depreciation and amortization	0.0	0.0
Income from equity investments	0.0	0.0
Other income (expenses), net	19.0	17.0
Interest expense, net	0.0	0.0
GBPC Impairment charge		0.0
Income tax expense (recovery)	0.0	0.0
Non-controlling interest in subsidiaries	0.0	0.0
Preferred stock dividends	0.0	0.0
Net income (loss) attributable to common shareholders	0.0	0.0
Capital expenditures	0.0	0.0
Segment Reporting Information, As at December 31		
Total assets	(1,257.0)	(1,443.0)
Investments subject to significant influence	0.0	0.0
Goodwill	0.0	0.0
Financing costs	95.0	13.0
Intersegment Eliminations | Regulated | Electric Revenue		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	(13.0)	(8.0)
Intersegment Eliminations | Regulated | Natural gas		
Segment Reporting Information, For the year ended December 31		
Fuel for generation and purchased power	0.0	0.0
Eliminations		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	(53.0)	(36.0)
Eliminations | Florida Electric Utility		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	8.0	7.0
Eliminations | Canadian Electric Utilities		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	0.0	0.0
Eliminations | Gas Utilities and Infrastructure		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	14.0	7.0
Eliminations | Other Electric Utilities		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	0.0	0.0
Eliminations | Other		
Segment Reporting Information, For the year ended December 31		
Total operating revenues	$ 31.0	$ 22.0

Segment Information (Geographical) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Revenues from External Customers and Long-Lived Assets [Line Items]		
Revenues	$ 7,563	$ 7,588
Property, Plant and Equipment, Net	24,376	22,996
Canada		
Revenues from External Customers and Long-Lived Assets [Line Items]		
Revenues	1,727	1,725
Property, Plant and Equipment, Net	4,878	4,689
United States		
Revenues from External Customers and Long-Lived Assets [Line Items]		
Revenues	5,310	5,346
Property, Plant and Equipment, Net	18,588	17,382
Barbados		
Revenues from External Customers and Long-Lived Assets [Line Items]		
Revenues	389	384
Property, Plant and Equipment, Net	576	583
The Bahamas		
Revenues from External Customers and Long-Lived Assets [Line Items]		
Revenues	137	122
Property, Plant and Equipment, Net	334	342
Dominica		
Revenues from External Customers and Long-Lived Assets [Line Items]		
Revenues	$ 0	$ 11

Segment Information (Narrative) (Details)	12 Months Ended Dec. 31, 2023
Segment Information [Abstract]	
Segment Reporting, Factors Used to Identify Entity's Reportable Segments	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.

Revenue (Disaggregation of Revenue by Major Source) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	$ 7,563	$ 7,588
Total operating revenues	7,563	7,588
Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Total operating revenues	3,548	3,280
Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	1,671	1,675
Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	526	518
Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Total operating revenues	1,510	1,697
Other		
Disaggregation of Revenue [Line Items]		
Total operating revenues	308	418
Operating		
Disaggregation of Revenue [Line Items]		
Total operating revenues	7,563	7,588
Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	3,556	3,287
Total operating revenues	3,556	3,287
Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	1,671	1,675
Total operating revenues	1,671	1,675
Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	526	518
Total operating revenues	526	518
Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	1,524	1,704
Total operating revenues	1,524	1,704
Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	339	440

Total operating revenues	339	440
Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	(53)	(36)
Total operating revenues	(53)	(36)
Eliminations | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Total operating revenues	8	7
Eliminations | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Eliminations | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Eliminations | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Total operating revenues	14	7
Eliminations | Other		
Disaggregation of Revenue [Line Items]		
Total operating revenues	31	22
Regulated | Other Electric And Regulatory		
Disaggregation of Revenue [Line Items]		
Total operating revenues	254	335
Non-Regulated		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	328	434
Total operating revenues	328	434
Non-Regulated | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Non-Regulated | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Non-Regulated | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Non-Regulated | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	21	16
Non-Regulated | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	339	440
Non-Regulated | Eliminations		
Disaggregation of Revenue [Line Items]		

Revenue from contract with customer	(32)	(22)
Electric Revenue | Regulated		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	7,235	7,154
Total operating revenues	5,746	5,473
Electric Revenue | Regulated | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	3,556	3,287
Electric Revenue | Regulated | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	1,671	1,675
Electric Revenue | Regulated | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	526	518
Electric Revenue | Regulated | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	1,503	1,688
Electric Revenue | Regulated | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	(21)	(14)
Electric Revenue | Regulated | Residential		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	4,124	3,617
Electric Revenue | Regulated | Residential | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	2,307	1,799
Electric Revenue | Regulated | Residential | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	910	834
Electric Revenue | Regulated | Residential | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	183	184
Electric Revenue | Regulated | Residential | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	724	800
Electric Revenue | Regulated | Residential | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Residential | Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0

Electric Revenue | Regulated | Commercial		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	2,256	2,039
Electric Revenue | Regulated | Commercial | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	1,083	869
Electric Revenue | Regulated | Commercial | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	463	427
Electric Revenue | Regulated | Commercial | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	285	282
Electric Revenue | Regulated | Commercial | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	425	461
Electric Revenue | Regulated | Commercial | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Commercial | Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Industrial		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	606	691
Electric Revenue | Regulated | Industrial | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	274	230
Electric Revenue | Regulated | Industrial | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	219	353
Electric Revenue | Regulated | Industrial | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	33	32
Electric Revenue | Regulated | Industrial | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	93	83
Electric Revenue | Regulated | Industrial | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Industrial | Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	(13)	(7)
Electric Revenue | Regulated | Other Electric		
Disaggregation of Revenue [Line Items]		

Revenue from contract with customer	443	432
Electric Revenue | Regulated | Other Electric | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	395	398
Electric Revenue | Regulated | Other Electric | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	41	28
Electric Revenue | Regulated | Other Electric | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	7	6
Electric Revenue | Regulated | Other Electric | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Other Electric | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Other Electric | Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Regulatory Deferrals		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	(510)	(21)
Electric Revenue | Regulated | Regulatory Deferrals | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	(522)	(27)
Electric Revenue | Regulated | Regulatory Deferrals | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Regulatory Deferrals | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	12	6
Electric Revenue | Regulated | Regulatory Deferrals | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Regulatory Deferrals | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Regulatory Deferrals | Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue from contract with customer	0	0
Electric Revenue | Regulated | Other Electric And Regulatory | Operating | Florida Electric Utility		

Disaggregation of Revenue [Line Items]		
Total operating revenues	19	18
Electric Revenue | Regulated | Other Electric And Regulatory | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	38	33
Electric Revenue | Regulated | Other Electric And Regulatory | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	6	8
Gas Revenue | Regulated		
Disaggregation of Revenue [Line Items]		
Total operating revenues	1,489	1,681
Gas Revenue | Regulated | Other Electric And Regulatory | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Total operating revenues	199	283
Marketing and trading margin | Non-Regulated		
Disaggregation of Revenue [Line Items]		
Total operating revenues	96	143
Marketing and trading margin | Non-Regulated | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Marketing and trading margin | Non-Regulated | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Marketing and trading margin | Non-Regulated | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Marketing and trading margin | Non-Regulated | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Marketing and trading margin | Non-Regulated | Operating | Other		
Disaggregation of Revenue [Line Items]		
Total operating revenues	96	143
Marketing and trading margin | Non-Regulated | Eliminations		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Energy sales | Non-Regulated | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Energy sales | Non-Regulated | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0

Energy sales | Non-Regulated | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Finance Income | Regulated | Repsol Energy Canada		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	62	61
Finance Income | Regulated | Operating | Florida Electric Utility | Repsol Energy Canada		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Finance Income | Regulated | Operating | Canadian Electric Utilities | Repsol Energy Canada		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Finance Income | Regulated | Operating | Other Electric Utilities | Repsol Energy Canada		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Finance Income | Regulated | Operating | Gas Utilities and Infrastructure | Repsol Energy Canada		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	62	61
Finance Income | Regulated | Operating | Other | Repsol Energy Canada		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Finance Income | Regulated | Eliminations | Repsol Energy Canada		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers		0
Other revenue | Regulated | Other Electric And Regulatory | Operating | Other		
Disaggregation of Revenue [Line Items]		
Total operating revenues	0	0
Other revenue | Regulated | Other Electric And Regulatory | Eliminations		
Disaggregation of Revenue [Line Items]		
Total operating revenues	(8)	(7)
Other revenue | Non-Regulated		
Disaggregation of Revenue [Line Items]		
Total operating revenues	25	22
Other revenue | Non-Regulated | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Total operating revenues	21	16
Other revenue | Non-Regulated | Operating | Other		
Disaggregation of Revenue [Line Items]		
Total operating revenues	27	16
Other revenue | Non-Regulated | Eliminations		
Disaggregation of Revenue [Line Items]		

Total operating revenues	(23)	(10)
Mark-To-Market | Non-Regulated		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	207	269
Mark-To-Market | Non-Regulated | Operating | Florida Electric Utility		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Mark-To-Market | Non-Regulated | Operating | Canadian Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Mark-To-Market | Non-Regulated | Operating | Other Electric Utilities		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Mark-To-Market | Non-Regulated | Operating | Gas Utilities and Infrastructure		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	0	0
Mark-To-Market | Non-Regulated | Operating | Other		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	216	281
Mark-To-Market | Non-Regulated | Eliminations		
Disaggregation of Revenue [Line Items]		
Revenue which does not represent revenues from contracts with customers	$ (9)	$ (12)

Revenue (Remaining Performance Obligations) (Narrative) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Revenue Remaining Performance Obligation Expected Timing Of Satisfaction [Line Items]		
Revenue, Remaining Performance Obligation, Amount	$ 488	$ 450
Revenue, Remaining Performance Obligation, Expected Timing Of Satisfaction (Year)	2043	
SeaCoast Gas Transmission, LLC | PGS		
Revenue Remaining Performance Obligation Expected Timing Of Satisfaction [Line Items]		
Revenue, Remaining Performance Obligation, Amount	$ 134	
Revenue, Remaining Performance Obligation, Expected Timing Of Satisfaction (Year)	2040	

Regulatory Assets and Liabilities (Regulated Assets) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Regulatory Assets [Line Items]		
Regulatory Assets, Current	$ 339	$ 602
Regulatory Assets, Long-term	2,766	3,018
Total regulatory assets	3,105	3,620
Deferred income tax regulatory assets		
Regulatory Assets [Line Items]		
Total regulatory assets	1,233	1,166
TEC capital cost recovery for early retired assets		
Regulatory Assets [Line Items]		
Total regulatory assets	671	674
NSPI FAM		
Regulatory Assets [Line Items]		
Total regulatory assets	395	307
Pension and post-retirement medical plan		
Regulatory Assets [Line Items]		
Total regulatory assets	364	369
Cost Recovery Clauses		
Regulatory Assets [Line Items]		
Total regulatory assets	151	707
Deferrals related to derivative instruments		
Regulatory Assets [Line Items]		
Total regulatory assets	88	30
Storm cost recovery clauses		
Regulatory Assets [Line Items]		
Total regulatory assets	52	138
Environmental Remediations		
Regulatory Assets [Line Items]		
Total regulatory assets	26	27
Stranded Cost Recovery		
Regulatory Assets [Line Items]		
Total regulatory assets	25	27
NMGC winter event gas cost recovery		
Regulatory Assets [Line Items]		
Total regulatory assets	0	69
Other		
Regulatory Assets [Line Items]		
Total regulatory assets	$ 100	$ 106

Regulatory Assets and Liabilities (Regulated Liabilities) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Regulatory Liabilities [Line Items]		
Regulatory Liability, Current	$ 168	$ 495
Regulatory Liability, Long-term	1,604	1,778
Total regulatory liabilities	1,772	2,273
Accumulated reserve - COR		
Regulatory Liabilities [Line Items]		
Total regulatory liabilities	849	895
Deferred income tax regulatory liabilities		
Regulatory Liabilities [Line Items]		
Total regulatory liabilities	830	877
Cost Recovery Clauses		
Regulatory Liabilities [Line Items]		
Total regulatory liabilities	32	70
BLPC Self-insurance fund ("SIF") (note 32)		
Regulatory Liabilities [Line Items]		
Total regulatory liabilities	29	30
Deferrals related to derivative instruments		
Regulatory Liabilities [Line Items]		
Total regulatory liabilities	17	230
NMGC gas hedge settlements (note 18)		
Regulatory Liabilities [Line Items]		
Total regulatory liabilities	0	162
Other		
Regulatory Liabilities [Line Items]		
Total regulatory liabilities	$ 15	$ 9

Regulatory Assets and Liabilities - Assets and Liabilities (Narrative) (Details) $ in Millions, $ in Millions	1 Months Ended			12 Months Ended					
	Sep. 30, 2022 USD ($)	Feb. 28, 2021 USD ($)	Jan. 31, 2020 USD ($)	Dec. 31, 2025 CAD ($)	Dec. 31, 2024 CAD ($)	Dec. 31, 2023 CAD ($)	Dec. 31, 2023 USD ($)	Dec. 31, 2022 CAD ($)	Jun. 15, 2021 USD ($)
Public Utilities, General Disclosures [Line Items]									
Regulatory Assets						$ 3,105		$ 3,620	
NMGC winter event gas cost recovery									
Public Utilities, General Disclosures [Line Items]									
Regulatory Assets						$ 0		$ 69	
GBPC | Hurricane | Loss from Catastrophes									
Public Utilities, General Disclosures [Line Items]									
Storm cost			$ 15						
Recovery Period						5 years			
GBPC | Steam turbine									
Public Utilities, General Disclosures [Line Items]									
Public Utilities, Property, Plant and Equipment, Amount of Loss (Recovery) on Plant Abandonment							$ 21		
NSPI									
Public Utilities, General Disclosures [Line Items]									
Storm cost						$ 10			
NSPI | Forecast									
Public Utilities, General Disclosures [Line Items]									
Storm cost				$ 10	$ 10				
Tampa Electric									
Public Utilities, General Disclosures [Line Items]									
Storm cost	$ 119						$ 29		
Recovery Period						15 years			
NMGC									
Public Utilities, General Disclosures [Line Items]									
Recovery Period						30 months			
Incremental gas cost		$ 108							

NMGC | NMGC winter event gas cost recovery	
Public Utilities, General Disclosures [Line Items]	
Regulatory Assets	$ 108

Regulatory Assets and Liabilities - Florida Electric Utility (Narrative) (Details) $ in Millions, $ in Millions				1 Months Ended	3 Months Ended	12 Months Ended					
	Nov. 17, 2023 USD ($)	Jan. 23, 2023 USD ($)	Jan. 19, 2022 USD ($)	Sep. 30, 2022 USD ($)	Sep. 30, 2023 USD ($)	Dec. 31, 2023 CAD ($)	Dec. 31, 2023 USD ($)	Dec. 31, 2022 CAD ($)	Aug. 16, 2023 USD ($)	Dec. 31, 2022 USD ($)	Dec. 31, 2021 USD ($)
Public Utilities, General Disclosures [Line Items]											
State income tax						11.00%	11.00%	15.00%			
Utilities Operating Expense, Depreciation and Amortization						$ 1,049		$ 952			
Regulatory Assets						3,105		3,620			
Florida Electric Utility | Operating											
Public Utilities, General Disclosures [Line Items]											
Utilities Operating Expense, Depreciation and Amortization						571		507			
Cost Recovery Clauses											
Public Utilities, General Disclosures [Line Items]											
Regulatory Assets						151		707			
Restoration Costs											
Public Utilities, General Disclosures [Line Items]											
Regulatory Assets						26		27			
Storm cost recovery clauses											
Public Utilities, General Disclosures [Line Items]											
Regulatory Assets						$ 52		$ 138			
Tampa Electric											
Public Utilities, General Disclosures [Line Items]											
Storm Damage Provision				$ 119			$ 29				
Recovery Period						15 years					
Tampa Electric | Big Bend Modernization Project | Unit 1 components | Florida Electric Utility | Operating											
Public Utilities, General Disclosures [Line Items]											
Estimated Amount of Investment										$ 876	

Public Utilities, Property, Plant and Equipment, Accumulated Depreciation						$ 91	
Tampa Electric | Storm cost recovery clauses							
Public Utilities, General Disclosures [Line Items]							
Storm Damage Provision		$ 35					
Regulatory Assets	$ 131				$ 134		
Approved reserve level	56						
Tampa Electric | Florida Public Service Commission							
Public Utilities, General Disclosures [Line Items]							
Recovery Period							15 years
Tampa Electric | Florida Public Service Commission | Florida Electric Utility | Operating							
Public Utilities, General Disclosures [Line Items]							
Public Utilities, Disclosure of Rate Matters			TEC is regulated by the FPSC and is also subject to regulation by the Federal Energy Regulatory Commission. The FPSC sets rates at a level that allows utilities such as TEC to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested	TEC is regulated by the FPSC and is also subject to regulation by the Federal Energy Regulatory Commission. The FPSC sets rates at a level that allows utilities such as TEC 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 TEC, the FPSC or other interested parties.	capital. Base rates are determined in FPSC rate setting hearings which can occur at the initiative of TEC, the FPSC or other interested parties.	
Allowed equity capital structure			54.00%	54.00%	
Public Utilities, Approved Rate Increase (Decrease), Amount	$ (22)				
Public Utilities, Requested Rate Increase (Decrease), Amount		$ 169			
Tampa Electric | Florida Public Service Commission | Additional adjustment for 2026 | Florida Electric Utility | Operating					
Public Utilities, General Disclosures [Line Items]					
Public Utilities, Approved Rate Increase (Decrease), Amount				$ (100)	
Tampa Electric | Florida Public Service Commission | Additional adjustment for 2027 | Florida Electric Utility | Operating					
Public Utilities, General Disclosures [Line Items]					
Public Utilities, Approved Rate Increase (Decrease), Amount				$ (70)	
Tampa Electric | Florida Public Service Commission | Cost Recovery Clauses | Florida Electric Utility | Operating					
Public Utilities, General Disclosures [Line Items]					
Approved regulated return on equity			10.20%	10.20%	10.20%

Public Utilities, Requested Rate Increase (Decrease), Amount	$ 518				
Recovery Period	21 months				
Tampa Electric | Florida Public Service Commission | Big Bend Modernization Project | Unit 1 components | Florida Electric Utility | Operating					
Public Utilities, General Disclosures [Line Items]					
Public Utilities, Property, Plant and Equipment, Plant in Service					$ 636
Public Utilities, Property, Plant and Equipment, Accumulated Depreciation					$ 267
Tampa Electric | Florida Public Service Commission | Projected Fuel Costs | Florida Electric Utility | Operating					
Public Utilities, General Disclosures [Line Items]					
Public Utilities, Requested Rate Increase (Decrease), Amount	$ (170)				
Tampa Electric | Florida Public Service Commission | Range, Minimum | Florida Electric Utility | Operating					
Public Utilities, General Disclosures [Line Items]					
Approved regulated return on equity		9.25%	9.25%	9.25%	
Tampa Electric | Florida Public Service Commission | Range, Minimum | Base rate effective January 2025 | Florida Electric Utility | Operating					
Public Utilities, General Disclosures [Line Items]					
Public Utilities, Approved Rate Increase (Decrease), Amount			$ (290)		
Tampa Electric | Florida Public Service Commission | Range, Maximum | Florida Electric Utility | Operating					

Public Utilities, General Disclosures [Line Items]			
Approved regulated return on equity	11.25%	11.25%	11.25%
Tampa Electric | Florida Public Service Commission | Range, Maximum | Base rate effective January 2025 | Florida Electric Utility | Operating			
Public Utilities, General Disclosures [Line Items]			
Public Utilities, Approved Rate Increase (Decrease), Amount		$ (320)	

Regulatory Assets and Liabilities - Canada Electric Utilities (Narrative) (Details) $ in Millions					3 Months Ended	12 Months Ended			24 Months Ended			
	Jan. 29, 2024 CAD ($)	Dec. 01, 2023 CAD ($)	Oct. 31, 2023 CAD ($)	Aug. 15, 2021	Jun. 30, 2023 CAD ($)	Dec. 31, 2024	Dec. 31, 2023 CAD ($) km	Dec. 31, 2022 CAD ($)	Dec. 31, 2023 CAD ($) km	Dec. 21, 2023 CAD ($)	Mar. 31, 2023 CAD ($)	Feb. 28, 2022 CAD ($)
Public Utilities, General Disclosures [Line Items]												
Regulatory Liabilities							$ 1,772	$ 2,273	$ 1,772			
Utilities Operating Expense, Depreciation and Amortization							1,049	952				
Contractual Obligation, to be Paid, Year One							2,698		2,698			
Contractual Obligation, to be Paid, Year Two							1,217		1,217			
Regulatory Assets							3,105	3,620	3,105			
Non-current assets							11,396	11,850	$ 11,396			
Canadian Electric Utilities | Operating												
Public Utilities, General Disclosures [Line Items]												
Utilities Operating Expense, Depreciation and Amortization							276	259				
NSPI												
Public Utilities, General Disclosures [Line Items]												
Storm cost							$ 10					
NSPI | Canadian Electric Utilities												
Public Utilities, General Disclosures [Line Items]												
Recovery Period							3 years		3 years			
NSPI | Canadian Electric Utilities | Operating												
Public Utilities, General Disclosures [Line Items]												
Public Utilities, Requested Rate Increase (Decrease), Amended, Percentage							6.90%					
Storm cost							$ 31					
Deferred storm rider							$ 21		$ 21			

NSPI | Canadian Electric Utilities | Operating | Nova Scotia Cap-and-Trade ("Cap-and-Trade") Program					
Public Utilities, General Disclosures [Line Items]					
Gas costs				166	
Credits purchased from provincial auctions				$ 6	
Compliance costs accrued					$ (166)
NSPI | Canadian Electric Utilities | Operating | Subsequent Event [Member]					
Public Utilities, General Disclosures [Line Items]					
Requested approval for sale of regulatory assets	$ 117				
Amortization and financing costs	$ 117				
Collection period of amortization and financing costs	10 years				
NSPI | Range, Minimum | Canadian Electric Utilities | Operating					
Public Utilities, General Disclosures [Line Items]					
Approved regulated return on equity			8.75%	8.75%	
NSPI | Range, Maximum | Canadian Electric Utilities | Operating					
Public Utilities, General Disclosures [Line Items]					
Approved regulated return on equity			9.25%	9.25%	
Regulated common equity component			40.00%		
NSPI | Scenario Plan | Canadian Electric Utilities | Operating					
Public Utilities, General Disclosures [Line Items]					
Public Utilities, Requested Rate Increase (Decrease), Amended, Percentage		6.50%			
NSPI | NSPI FAM | Canadian Electric Utilities | Operating					

Public Utilities, General Disclosures [Line Items]									
Increase to regulatory assets				$ 51					
NSPI | UARB | Canadian Electric Utilities | Operating									
Public Utilities, General Disclosures [Line Items]									
Amount requested to defer operating costs incurred from storm restoration		$ 24							
Non-current assets					$ 24		24		
NSPI | UARB | Canadian Electric Utilities | Operating | NSP Maritime Link Inc.									
Public Utilities, General Disclosures [Line Items]									
Holdback payable					$ 4	$ 8	$ 12		
Estimate of possible percentage of receiving deliveries					90.00%		90.00%		
Monthly holdback amount	$ 4					$ 2			
Percent of contracted annual amount					10.00%		10.00%		
Emera Newfoundland and Labrador Holdings Inc. | Canadian Electric Utilities | Operating | NSP Maritime Link Inc.									
Public Utilities, General Disclosures [Line Items]									
Public Utilities, Equipment, Transmission and Distribution					$ 1,800		$ 1,800		
Number of pipelines					2				
Length Of Pipeline | km					170		170		
Regulatory Liabilities									$ 1,800
Costs not recoverable for rate approval									9
Costs not recoverable for rate approval net of tax									$ 7
Holdback payable					$ 4				
Contractual Obligation, to be Paid, Year One					$ 164		$ 164	$ 164	
Energy Delivery Commitments and Contracts, Term			35 years						
Emera Newfoundland and Labrador Holdings Inc. | Range,									

Minimum | Canadian Electric Utilities | Operating | NSP Maritime Link Inc.		
Public Utilities, General Disclosures [Line Items]		
Approved regulated return on equity	8.75%	
Emera Newfoundland and Labrador Holdings Inc. | Range, Maximum | Canadian Electric Utilities | Operating | NSP Maritime Link Inc.		
Public Utilities, General Disclosures [Line Items]		
Approved regulated return on equity	9.25%	
Equity ratio	30.00%	30.00%

Regulatory Assets and Liabilities - Gas Utilities and Infrastructure (Narrative) (Details) $ in Millions, $ in Millions				1 Months Ended	12 Months Ended		24 Months Ended
	Nov. 09, 2023 USD ($)	Sep. 14, 2023 USD ($)	May 20, 2022	Feb. 28, 2021 USD ($)	Dec. 31, 2023 CAD ($) km	Dec. 31, 2022 CAD ($)	Dec. 31, 2023 USD ($)
Public Utilities, General Disclosures [Line Items]							
Accumulated depreciation					$ 9,994	$ 9,574	
Regulatory assets					3,105	3,620	
Storm cost recovery clauses							
Public Utilities, General Disclosures [Line Items]							
Regulatory assets					$ 52	$ 138	
Emera Brunswick Pipeline Company Limited | Gas Utilities and Infrastructure							
Public Utilities, General Disclosures [Line Items]							
Length Of Pipeline | km					145		
Emera Brunswick Pipeline Company Limited | Gas Utilities and Infrastructure | Operating							
Public Utilities, General Disclosures [Line Items]							
Length Of Pipeline | km					145		
Public Utilities, Property, Plant and Equipment, Transmission and Distribution, Useful Life					25 years		
NMGC							
Public Utilities, General Disclosures [Line Items]							
Incremental gas cost				$ 108			
NMGC | Gas Utilities and Infrastructure | Operating							
Public Utilities, General Disclosures [Line Items]							
Approved regulated return on equity					9.375%	9.375%	
Allowed equity capital structure					52.00%	52.00%	
NMGC | New Mexico Public Regulatory | Gas Utilities and Infrastructure | Operating							
Public Utilities, General Disclosures [Line Items]							
Approved regulated return on equity			10.50%				
Public Utilities, Requested Rate Increase (Decrease), Amount		$ 49					
PGS | Gas Utilities and Infrastructure | Operating							
Public Utilities, General Disclosures [Line Items]							
Allowed equity capital structure					54.70%		
Accumulated Depreciation, Depletion and Amortization, Property, Plant and Equipment, Period Decrease					$ 20	$ 14	$ 34

PGS | Gas Utilities and Infrastructure | Operating | Scenario Plan			
Public Utilities, General Disclosures [Line Items]			
Approved regulated return on equity	10.15%		
Allowed equity capital structure	54.70%		
Phase-in Plan, Amount of Capitalized Costs Recovered	$ 11		
Public Utilities, Approved Rate Increase (Decrease), Amount	118		
PGS | Gas Utilities and Infrastructure | Operating | Cast Iron/Bare Steel Pipe Replacement | Scenario Plan			
Public Utilities, General Disclosures [Line Items]			
Phase-in Plan, Amount of Capitalized Costs Recovered	$ 107		
PGS | Range, Minimum | Gas Utilities and Infrastructure | Operating			
Public Utilities, General Disclosures [Line Items]			
Approved regulated return on equity		8.90%	
PGS | Range, Minimum | Gas Utilities and Infrastructure | Operating | Scenario Plan			
Public Utilities, General Disclosures [Line Items]			
Allowed equity capital structure	54.70%		
PGS | Range, Maximum | Gas Utilities and Infrastructure | Operating			
Public Utilities, General Disclosures [Line Items]			
Approved regulated return on equity			11.00%
PGS | Mid Point | Gas Utilities and Infrastructure | Operating			
Public Utilities, General Disclosures [Line Items]			
Approved regulated return on equity		9.90%	
BPLC			
Public Utilities, General Disclosures [Line Items]			
Approved regulated return on equity		10.00%	10.00%

Regulatory Assets and Liabilities - Other Electric Utilities (Narrative) (Details) $ in Millions, $ in Millions	1 Months Ended			12 Months Ended	
	Apr. 01, 2022 USD ($)	Sep. 30, 2022 USD ($)	Jan. 31, 2022	Dec. 31, 2023 CAD ($)	Dec. 31, 2022 CAD ($)
Public Utilities, General Disclosures [Line Items]					
Income tax (expense) recovery				$ (128)	$ (185)
Regulatory liabilities				1,772	2,273
Other Electric Utilities | Operating					
Public Utilities, General Disclosures [Line Items]					
Income tax (expense) recovery				$ 0	$ 0
Barbados Light and Power Company Limited					
Public Utilities, General Disclosures [Line Items]					
Approved regulated return on equity				10.00%	10.00%
Barbados Light and Power Company Limited | Other Electric Utilities | Operating					
Public Utilities, General Disclosures [Line Items]					
Cost sharing ratio				50.00%	
Barbados Light and Power Company Limited | Fair Trading Commission | Other Electric Utilities | Operating					
Public Utilities, General Disclosures [Line Items]					
Approved regulated return on equity		11.75%			
Allowed equity capital structure		55.00%			
Deferred Tax Liabilities, Regulatory Assets and Liabilities		$ 5.0			
Public Utilities, Interim Rate Increase (Decrease), Amount		1.0			
Regulatory liabilities		50.0			
Accumulated depreciation		$ 16.0			
GBPC | GBPA | Other Electric Utilities | Operating					
Public Utilities, General Disclosures [Line Items]					
Public Utilities, Approved Rate Increase (Decrease), Amount	$ 3.5				
Approved regulated return on equity				8.32%	8.23%
GBPC | GBPA | Other Electric Utilities | Operating | Scenario Plan					
Public Utilities, General Disclosures [Line Items]					
Approved regulated return on equity			12.84%		

Investments Subject to Significant Influence and Equity Income (Summary of Investments Subject to Significant Influence) (Details) - CAD ($) $ in Millions	12 Months Ended Dec. 31, 2023	Dec. 31, 2022	Dec. 31, 2015
Schedule of Equity Method Investments [Line Items]			
Investments subject to significant influence	$ 1,402	$ 1,418	
Income (loss) from equity investments and subsidiaries	146	129	
Equity Method Investment, Summarized Financial Information [Abstract]			
Other long-term liabilities	820	825	
Equity Method Investee			
Schedule of Equity Method Investments [Line Items]			
Investments subject to significant influence	1,402	1,418	
Income (loss) from equity investments and subsidiaries	146	129	
Equity Method Investee | Emera Inc.			
Equity Method Investment, Summarized Financial Information [Abstract]			
Equity Method Investment, Difference Between Carrying Amount and Underlying Equity	10		
LIL | Equity Method Investee			
Schedule of Equity Method Investments [Line Items]			
Investments subject to significant influence	747	740	
Income (loss) from equity investments and subsidiaries	$ 63	58	
Percentage of Ownership	31.00%		
LIL | Equity Method Investee | Emera Inc.			
Schedule of Equity Method Investments [Line Items]			
Percentage of Ownership	31.00%		
LIL | Equity Method Investee | Class B units | NSP Maritime Link Inc Project			
Schedule of Equity Method Investments [Line Items]			
100% ownership	100.00%		
LIL | Equity Method Investee | Total Units Issued [Member]			
Schedule of Equity Method Investments [Line Items]			
Percentage of Ownership	24.50%		
NSPML | Equity Method Investee			
Schedule of Equity Method Investments [Line Items]			
Investments subject to significant influence	$ 489	501	
Income (loss) from equity investments and subsidiaries	$ 46	29	
NSPML | Equity Method Investee | NSP Maritime Link Inc Project			
Schedule of Equity Method Investments [Line Items]			
100% ownership	100.00%		

M&NP | Equity Method Investee			
Schedule of Equity Method Investments [Line Items]			
Investments subject to significant influence	$ 118	128	
Income (loss) from equity investments and subsidiaries	$ 21	21	
Percentage of Ownership	12.90%		
M&NP | Equity Method Investee | Emera Inc.			
Schedule of Equity Method Investments [Line Items]			
Percentage of Ownership	12.90%		
Lucelec | Equity Method Investee			
Schedule of Equity Method Investments [Line Items]			
Investments subject to significant influence	$ 48	49	
Income (loss) from equity investments and subsidiaries	$ 4	4	
Percentage of Ownership	19.50%		
Lucelec | Equity Method Investee | Emera Inc.			
Schedule of Equity Method Investments [Line Items]			
Percentage of Ownership	19.50%		
Bear Swamp			
Equity Method Investment, Summarized Financial Information [Abstract]			
Other long-term liabilities	$ 81	95	$ 179
Bear Swamp | Equity Method Investee			
Schedule of Equity Method Investments [Line Items]			
Investments subject to significant influence	0	0	
Income (loss) from equity investments and subsidiaries	$ 12	$ 17	
Percentage of Ownership	50.00%		
Bear Swamp | Equity Method Investee | Emera Inc.			
Schedule of Equity Method Investments [Line Items]			
Percentage of Ownership	50.00%		
Maritime Link And LIL | Plan, subject to approval			
Schedule of Equity Method Investments [Line Items]			
Percentage of Ownership	49.00%		

Investments Subject to Significant Influence and Equity Income (Summary of Investments Subject to Significant Influence - NSPML) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022	Dec. 31, 2021
Balance Sheets			
Current assets	$ 3,708	$ 4,896	
Property, plant and equipment	24,376	22,996	
Regulatory assets	2,766	3,018	
Non-current assets	11,396	11,850	
Total assets	39,480	39,742	
Current liabilities	4,544	7,287	
Non-current liabilities	22,848	21,014	
Equity	12,088	11,441	$ 10,150
Total liabilities and equity	39,480	39,742	
Variable Interest Entity, Not Primary Beneficiary | NSPML			
Balance Sheets			
Current assets	21	17	
Property, plant and equipment	1,473	1,517	
Regulatory assets	272	265	
Non-current assets	29	29	
Total assets	1,795	1,828	
Current liabilities	48	48	
Long-term debt	1,109	1,149	
Non-current liabilities	149	130	
Equity	489	501	
Total liabilities and equity	$ 1,795	$ 1,828	

Other Income, Net (Components of Other Expense, Net) (Details) - CAD ($) $ in Millions		12 Months Ended	
	Dec. 15, 2022	Dec. 31, 2023	Dec. 31, 2022
Other Income, Net [Abstract]			
Interest income		$ 43	$ 25
AFUDC		38	52
Pension non-current service cost recovery		35	24
FX gains (losses)		20	(26)
TECO Guatemala Holdings award	$ 63	0	63
Other		22	7
Other income (expenses), net		$ 158	$ 145

Interest Expense, Net (Components of Interest Expense, Net) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Interest Expense, Net [Abstract]		
Interest on debt	$ 954	$ 727
Allowance for borrowed funds used during construction	(16)	(21)
Other	(13)	3
Interest expense, net	$ 925	$ 709

Income Taxes (Reconciliation of Effective Income Tax Rate) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Income before provision for income taxes	$ 1,173	$ 1,194
Statutory income tax rate	29.00%	29.00%
Income taxes, at statutory income tax rates	$ 340	$ 346
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	(72)	(70)
Tax credits	(53)	(18)
Foreign tax rate variance	(36)	(44)
Amortization of deferred income tax regulatory liabilities	(33)	(33)
Tax effect of equity earnings	(15)	(10)
GBPC impairment charge	0	21
Other	(3)	(7)
Income tax expense	$ 128	$ 185
Effective income tax rate	11.00%	15.00%
Regulatory Liabilities	$ 1,772	$ 2,273
Incremental tax benefits payable to customers [Member]		
Regulatory Liabilities	$ 30	$ 9

Income Taxes (Composition of Taxes on Income from Continuing Operations) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Components of Income Tax Expense (Benefit), Continuing Operations [Abstract]		
Deferred income taxes	$ 97	$ 152
Income tax expense	128	185
Canada		
Components of Income Tax Expense (Benefit), Continuing Operations [Abstract]		
Current income taxes	26	25
Deferred income taxes	93	122
Operating loss carry forwards	(93)	(94)
United States		
Components of Income Tax Expense (Benefit), Continuing Operations [Abstract]		
Current income taxes	5	8
Deferred income taxes	128	252
Investment tax credits	(29)	(7)
Operating loss carry forwards	$ (2)	$ (121)

Income Taxes (Composition of Income Before Provision for Income Taxes) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Composition of taxes on income from continuing operations [Line items]		
Income before provision for income taxes	$ 1,173	$ 1,194
Canada		
Composition of taxes on income from continuing operations [Line items]		
Income before provision for income taxes	171	173
United States		
Composition of taxes on income from continuing operations [Line items]		
Income before provision for income taxes	964	1,063
Other		
Composition of taxes on income from continuing operations [Line items]		
Income before provision for income taxes	$ 38	$ (42)

Income Taxes (Schedule of Deferred Income Tax Assets and Liabilities) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Deferred income tax assets:		
Tax loss carryforwards	$ 1,195	$ 1,207
Tax credit carryforwards	454	415
Derivative instruments	205	45
Regulatory liabilities	175	264
Other	372	341
Total deferred income tax assets before valuation allowance	2,401	2,272
Valuation allowance	(363)	(312)
Total deferred income tax assets after valuation allowance	2,038	1,960
Deferred income tax (liabilities):		
PP&E	(3,223)	(2,981)
Derivative instruments	(235)	(125)
Investments subject to significant influence	(216)	(181)
Regulatory assets	(196)	(310)
Other	(312)	(322)
Total deferred income tax liabilities	(4,182)	(3,919)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax assets	208	237
Long-term deferred income tax liabilities	(2,352)	(2,196)
Net deferred income tax liabilities	$ (2,144)	$ (1,959)

Income Taxes (Net Operating Loss ("NOL"), Capital Loss and Tax Credit Carryforwards and Their Expiration Periods) (Details) $ in Millions	12 Months Ended Dec. 31, 2023 CAD ($)
Canada | Capital loss	
Composition of taxes on income from continuing operations [Line items]	
Gross Tax Carryforwards	$ 73
Subject to Valuation Allowance	(73)
Net Tax Credit Carryforwards	$ 0
Expiration period	Indefinite
Canada | NOL	
Composition of taxes on income from continuing operations [Line items]	
Gross Tax Carryforwards	$ 2,914
Subject to Valuation Allowance	(1,164)
Net Tax Credit Carryforwards	$ 1,750
Expiration period	2026 - 2043
United States | NOL	
Composition of taxes on income from continuing operations [Line items]	
Gross Tax Carryforwards	$ 1,360
Subject to Valuation Allowance	(1)
Net Tax Credit Carryforwards	$ 1,359
Expiration period	2036 - Indefinite
United States | Tax credit	
Composition of taxes on income from continuing operations [Line items]	
Gross Tax Carryforwards	$ 454
Subject to Valuation Allowance	(3)
Net Tax Credit Carryforwards	$ 451
Expiration period	2025 - 2043
State | NOL	
Composition of taxes on income from continuing operations [Line items]	
Gross Tax Carryforwards	$ 1,003
Subject to Valuation Allowance	(1)
Net Tax Credit Carryforwards	$ 1,002
Expiration period	2026 - Indefinite
Other | NOL	
Composition of taxes on income from continuing operations [Line items]	
Gross Tax Carryforwards	$ 81
Subject to Valuation Allowance	(28)
Net Tax Credit Carryforwards	$ 53
Expiration period	2024 - 2030

Income Taxes (Details of Change in Unrecognized Tax Benefits) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Reconciliation of Unrecognized Tax Benefits, Excluding Amounts Pertaining to Examined Tax Returns [Roll Forward]		
Beginning, January 1	$ 33	$ 28
Increases due to tax positions related to current year	5	5
Increases due to tax positions related to a prior year	1	2
Decreases due to tax positions related to a prior year	(2)	(2)
Balance, December 31	$ 37	$ 33

Income Taxes (Unrecognized tax benefits) (Details) - CAD ($)	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Significant Change in Unrecognized Tax Benefits is Reasonably Possible [Line Items]		
Temporary Differences/Potential change	$ 4,700,000,000	$ 3,800,000,000
Net amount in dispute	126,000,000	126,000,000
Prepaid amount in dispute	55,000,000	
Deferred Tax Assets, Allowance	363,000,000	312,000,000
Unrecognized Tax Benefits, Income Tax Penalties and Interest Accrued [Abstract]		
Amount that could affect effective tax rate	37,000,000	33,000,000
Accrued interest	9,000,000	7,000,000
Income Tax Examination, Interest Expense	2,000,000	$ 1,000,000
Accrued penalties	$ 0	

Common Stock (Summary of Issued and Outstanding Common Stock) (Details) - CAD ($) shares in Thousands, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Increase (Decrease) In Common Stock Value [Roll Forward]		
Beginning Balance	$ 7,762	
Issuance of common stock	397	$ 248
Senior management stock options exercised and Employee Share Purchase Plan ("ECSPP")	32	36
Ending Balance	$ 8,462	$ 7,762
Increase (Decrease) in Stockholders' Equity [Roll Forward]		
Beginning Balance	269,950	261,070
Issuance of common stock (shares)	8,290	4,070
Issued under Purchase Plans at market rate	5,260	4,210
Options exercised under senior management share option plan	620	600
Ending Balance	284,120	269,950
Common Stock		
Increase (Decrease) In Common Stock Value [Roll Forward]		
Beginning Balance	$ 7,762	$ 7,242
Issuance of common stock	397	248
Issued under Purchase Plans at market rate	272	238
Senior management stock options exercised and Employee Share Purchase Plan ("ECSPP")	31	34
Ending Balance	$ 8,462	$ 7,762

Common Stock (Narrative) (Details) - CAD ($) $ / shares in Units, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Debt Instrument [Line Items]		
Issuance of common stock (shares)	8,290,000	4,070,000.00
Gross proceeds from Issuance of Common Stock	$ 424	$ 277
Percentage of outstanding stock maximum	10.00%	
ATM Program		
Debt Instrument [Line Items]		
Maximum common stock issued from treasury amount	$ 600	
ATM Program | Common Stock		
Debt Instrument [Line Items]		
Issuance of common stock (shares)	8,287,037	4,072,469
Gross proceeds from Issuance of Common Stock	$ 400	$ 250
Net proceeds from issuance of common stock	$ 397	$ 248
Average price per share, issued	$ 48.27	$ 61.31
Employee Stock Option Plan		
Debt Instrument [Line Items]		
Common Stock, Capital Shares Reserved for Future Issuance	6,000,000	6,000,000
Share Unit Plans		
Debt Instrument [Line Items]		
Common Stock, Capital Shares Reserved for Future Issuance	2,000,000	2,700,000
Dividend Reinvestment		
Debt Instrument [Line Items]		
Common Stock, Capital Shares Reserved for Future Issuance	18,000,000	10,000,000

Earnings Per Share (Computation of Basic and Diluted Earnings per Share) (Details) - CAD ($) $ / shares in Units, shares in Millions, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Numerator		
Net income attributable to common shareholders	$ 977.7	$ 945.1
Diluted numerator	$ 977.7	$ 945.1
Denominator		
Weighted average shares of common stock outstanding - basic	273.6	265.5
Stock-based compensation	0.2	0.4
Weighted average shares of common stock outstanding- diluted	273.8	265.9
Earnings per common share		
Basic	$ 3.57	$ 3.56
Diluted	$ 3.57	$ 3.55

Accumulated Other Comprehensive Income (Components of Accumulated Other Comprehensive Income) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Accumulated Other Comprehensive Income (Loss) [Line Items]		
Beginning Balance	$ 11,441	$ 10,150
Net current period other comprehensive income (loss)	(273)	553
Ending Balance	12,088	11,441
Accumulated Other Comprehensive Income (Loss)		
Accumulated Other Comprehensive Income (Loss) [Line Items]		
Beginning Balance	578	25
Other comprehensive income (loss) before reclassifications	(232)	531
Amounts reclassified from accumulated other comprehensive income loss	(41)	22
Net current period other comprehensive income (loss)	(273)	553
Ending Balance	305	578
Unrealized (loss) gain on translation of self-sustaining foreign operations		
Accumulated Other Comprehensive Income (Loss) [Line Items]		
Beginning Balance	639	10
Other comprehensive income (loss) before reclassifications	(270)	629
Amounts reclassified from accumulated other comprehensive income loss	0	0
Net current period other comprehensive income (loss)	(270)	629
Ending Balance	369	639
Net change in net investment hedges		
Accumulated Other Comprehensive Income (Loss) [Line Items]		
Beginning Balance	(62)	35
Other comprehensive income (loss) before reclassifications	38	(97)
Amounts reclassified from accumulated other comprehensive income loss	0	0
Net current period other comprehensive income (loss)	38	(97)
Ending Balance	(24)	(62)
Losses on derivatives recognized as cash flow hedges		
Accumulated Other Comprehensive Income (Loss) [Line Items]		
Beginning Balance	16	18
Other comprehensive income (loss) before reclassifications		0
Amounts reclassified from accumulated other comprehensive income loss	(2)	(2)
Net current period other comprehensive income (loss)	(2)	(2)
Ending Balance	14	16
Net change on available-for-sale investments		
Accumulated Other Comprehensive Income (Loss) [Line Items]		
Beginning Balance	(2)	(1)
Other comprehensive income (loss) before reclassifications	0	(1)
Amounts reclassified from accumulated other comprehensive income loss	0	0

Net current period other comprehensive income (loss)	0	(1)
Ending Balance	(2)	(2)
Net change in unrecognized pension and post-retirement benefit costs		
Accumulated Other Comprehensive Income (Loss) [Line Items]		
Beginning Balance	(13)	(37)
Other comprehensive income (loss) before reclassifications	0	0
Amounts reclassified from accumulated other comprehensive income loss	(39)	24
Net current period other comprehensive income (loss)	(39)	24
Ending Balance	$ (52)	$ (13)

Accumulated Other Comprehensive Income (Reclassifications out of Accumulated Other Comprehensive Income (Loss)) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Total operating revenues	$ 7,563	$ 7,588
Interest expense, net (note 9)	(925)	(709)
Other income, net (note 8)	158	145
Income tax (expense) recovery	(128)	(185)
Net income	1,045	1,009
Reclassification out of Accumulated Other Comprehensive Income [Member]		
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Net income	(41)	22
Reclassification out of Accumulated Other Comprehensive Income [Member] | Losses (gain) on derivatives recognized as cash flow hedges		
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Income tax (expense) recovery	(1)	(1)
Reclassification out of Accumulated Other Comprehensive Income [Member] | Losses (gain) on derivatives recognized as cash flow hedges | Interest rate hedge		
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Interest expense, net (note 9)	(2)	(2)
Reclassification out of Accumulated Other Comprehensive Income [Member] | Net change in unrecognized pension and post-retirement benefit costs		
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Total before tax	(38)	25
Income tax (expense) recovery	1	1
Net income	(39)	24
Reclassification out of Accumulated Other Comprehensive Income [Member] | Actuarial (gains) losses		
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Other income, net (note 8)	0	10
Reclassification out of Accumulated Other Comprehensive Income [Member] | Past service costs (gains)		
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Other income, net (note 8)	2	0

Reclassification out of Accumulated Other Comprehensive Income [Member] | Amounts reclassified into obligations		
Reclassification Adjustment out of Accumulated Other Comprehensive Income [Line Items]		
Pension and post-retirement benefits	$ (40)	$ 15

Inventory (Components of Inventory) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Inventory [Abstract]		
Fuel	$ 382	$ 404
Materials	408	365
Inventory Total	$ 790	$ 769

Derivatives Instruments (Derivative Assets and Liabilities) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
HFT derivatives		
Derivative Assets	$ 348	$ 429
Derivative Liabilities	567	1,301
Other derivatives		
Other, Derivative Assets	22	5
Other, Derivative Liabilities	7	28
Derivative Assets		
Total gross current derivative assets	389	690
Total impact of master netting agreements	(149)	(294)
Derivative Asset, Total	240	396
Derivative Assets, Current	174	296
Derivative Assets, Long-term	66	100
Derivative Liabilities		
Total gross current derivative liabilities	653	1,372
Total impact of master netting agreements	(149)	(294)
Derivative Liabilities, Total	504	1,078
Derivative Liabilities, Current	386	888
Derivative Liabilities, Long-term	118	190
Equity derivatives		
Other derivatives		
Other, Derivative Assets	4	0
Other, Derivative Liabilities	0	5
FX forwards		
Other derivatives		
Other, Derivative Assets	18	5
Other, Derivative Liabilities	7	23
Power swaps and physical contracts		
HFT derivatives		
Derivative Assets	29	89
Derivative Liabilities	36	77
Natural gas swaps, futures, forwards, physical contracts		
HFT derivatives		
Derivative Assets	319	340
Derivative Liabilities	531	1,224
Regulatory deferral		
HFT derivatives		
Derivative Assets	19	256
Derivative Liabilities	79	43
Derivative Assets		

Total impact of master netting agreements	(3)	(18)
Derivative Liabilities		
Total impact of master netting agreements	(3)	(18)
Regulatory deferral | Commodity swaps and forwards		
Regulatory deferral		
Regulatory deferral, Derivative Assets	16	186
Regulatory deferral, Derivative Liabilities	76	42
Regulatory deferral | FX forwards		
HFT derivatives		
Derivative Assets	3	18
Derivative Liabilities	3	1
Regulatory deferral | Physical natural gas purchases and sales [Member]		
HFT derivatives		
Derivative Assets	0	52
Derivative Liabilities	0	0
HFT derivatives		
Derivative Assets		
Total impact of master netting agreements	(146)	(276)
Derivative Liabilities		
Total impact of master netting agreements	$ (146)	$ (276)

Derivatives Instruments (Cash Flow Hedges Recorded in AOCI) (Details) - CAD ($) $ in Millions		12 Months Ended	
	May 26, 2021	Dec. 31, 2023	Dec. 31, 2022
Cash Flow Hedges			
Realized gain in interest expense, net		$ 2	$ 2
Total gains in net income		2	2
Total unrealized gain in AOCI - effective portion, net of tax		14	$ 16
Unrealized gains currently in AOCI to be reclassified into net income within the next twelve months		$ 2	
Cash flow hedges | Treasury lock			
Cash Flow Hedges			
Derivative gain loss amortization period	10 years		
Total unrealized gain in AOCI - effective portion, net of tax	$ 19		

Derivatives Instruments (Changes in Realized and Unrealized Gains (Losses) on Derivatives Receiving Regulatory Deferral) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss) on derivatives receiving regulatory deferral	$ 666	$ (206)
FX forwards		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	17	(24)
Regulatory deferral | Physical natural gas purchases		
Derivative Instruments, Gain (Loss) [Line Items]		
Total change derivative instruments on derivatives receiving regulatory deferral	(52)	(36)
Regulatory deferral | Physical natural gas purchases | Regulatory Assets		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss) on derivatives receiving regulatory deferral	0	0
Realized (gain) loss on derivatives receiving regulatory deferral	0	0
Regulatory deferral | Physical natural gas purchases | Regulatory Liabilities		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss) on derivatives receiving regulatory deferral	(3)	28
Realized (gain) loss on derivatives receiving regulatory deferral	0	0
Regulatory deferral | Physical natural gas purchases | Inventory		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	0	0
Regulatory deferral | Physical natural gas purchases | Regulated fuel for generation and purchased		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	(49)	(64)
Regulatory deferral | Physical natural gas purchases | Other		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	0	0
Regulatory deferral | Commodity swaps and forwards		
Derivative Instruments, Gain (Loss) [Line Items]		
Total change derivative instruments on derivatives receiving regulatory deferral	(204)	14
Regulatory deferral | Commodity swaps and forwards | Regulatory Assets		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss) on derivatives receiving regulatory deferral	(109)	(69)
Realized (gain) loss on derivatives receiving regulatory deferral	(5)	48
Regulatory deferral | Commodity swaps and forwards | Regulatory Liabilities		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss) on derivatives receiving regulatory deferral	(73)	343
Realized (gain) loss on derivatives receiving regulatory deferral	2	(41)

Regulatory deferral | Commodity swaps and forwards | Inventory		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	4	(121)
Regulatory deferral | Commodity swaps and forwards | Regulated fuel for generation and purchased		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	(9)	(146)
Regulatory deferral | Commodity swaps and forwards | Other		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	(14)	0
Regulatory deferral | FX forwards		
Derivative Instruments, Gain (Loss) [Line Items]		
Total change derivative instruments on derivatives receiving regulatory deferral	(17)	18
Regulatory deferral | FX forwards | Regulatory Assets		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss) on derivatives receiving regulatory deferral	(3)	1
Realized (gain) loss on derivatives receiving regulatory deferral	0	0
Regulatory deferral | FX forwards | Regulatory Liabilities		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss) on derivatives receiving regulatory deferral	0	16
Realized (gain) loss on derivatives receiving regulatory deferral	0	0
Regulatory deferral | FX forwards | Inventory		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	(10)	1
Regulatory deferral | FX forwards | Regulated fuel for generation and purchased		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	(4)	0
Regulatory deferral | FX forwards | Other		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized (gain) loss on derivatives receiving regulatory deferral	$ 0	$ 0

Derivatives Instruments (Notional Volumes of Outstanding Derivatives Designated for Regulatory Deferral) (Details) $ in Millions	12 Months Ended Dec. 31, 2023 CAD ($) MMBTU MWh t
Commodity swaps and forwards | Coal | 2024	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh | t	1
Commodity swaps and forwards | Coal | 2025-2026	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh | t	0
Commodity swaps and forwards | Natural gas | 2024	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh	16
Commodity swaps and forwards | Natural gas | 2025-2026	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh	10
Commodity swaps and forwards | Power | 2024	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh | MWh	1
Commodity swaps and forwards | Power | 2025-2026	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh | MWh	1
Physical natural gas purchases | Natural gas | 2024	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh	7
Physical natural gas purchases | Natural gas | 2025-2026	
Derivative [Line Items]	
Natural Gas (Mmbtu) / Power (MWh) | MWh	6
Foreign Exchange Swaps and Forward Contracts | 2024	
Derivative [Line Items]	
Notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle | $	$ 241
Weighted average rate	1.3155
% of USD requirements	63.00%
Foreign Exchange Swaps and Forward Contracts | 2025-2026	
Derivative [Line Items]	
Notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle | $	$ 70
Weighted average rate	1.3197
% of USD requirements	17.00%

Derivatives Instruments (Realized and Unrealized Gains (Losses) on HFT Derivatives) (Details) - HFT derivatives - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Derivative Instruments, Gain (Loss) [Line Items]		
Realized and unrealized gains (losses) with respect to HFT derivatives	$ 1,037	$ 64
Operating revenues | Power | Non-Regulated		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized and unrealized gains (losses) with respect to HFT derivatives	(6)	17
Operating revenues | Natural gas | Non-Regulated		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized and unrealized gains (losses) with respect to HFT derivatives	$ 1,043	$ 47

Derivatives Instruments (Notional Volumes of Outstanding HFT Derivatives) (Details) - HFT derivatives MWh in Millions, MMBTU in Millions	12 Months Ended Dec. 31, 2023 MWh MMBTU
Power | Purchases | 2024	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	1
Power | Purchases | 2025	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Power | Purchases | 2026	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Power | Purchases | 2027	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Power | Purchases | 2028 and thereafter	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Power | Sales | 2024	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	1
Power | Sales | 2025	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Power | Sales | 2026	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Power | Sales | 2027	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Power | Sales | 2028 and thereafter	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MWh	0
Natural gas | Purchases | 2024	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MMBTU	296
Natural gas | Purchases | 2025	
Derivative [Line Items]	
Notional volumes of outstanding derivatives that are expected to settle | MMBTU	80
Natural gas | Purchases | 2026	

Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 50
Natural gas | Purchases | 2027
Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 38
Natural gas | Purchases | 2028 and thereafter
Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 30
Natural gas | Sales | 2024
Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 338
Natural gas | Sales | 2025
Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 86
Natural gas | Sales | 2026
Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 16
Natural gas | Sales | 2027
Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 6
Natural gas | Sales | 2028 and thereafter
Derivative [Line Items]
Notional volumes of outstanding derivatives that are expected to settle | MMBTU 4

Derivatives Instruments (Realized and Unrealized Gains (Losses) on Other Derivatives) (Details) - CAD ($) shares in Millions, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Derivative Instruments, Gain (Loss) [Line Items]		
Equity derivative hedges, return of shares	2.9	
FX forwards		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized gains (loss)	$ 17	$ (24)
FX forwards | OM&G		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss)	0	0
Realized gains (loss)	0	0
FX forwards | Other income, net		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss)	28	(18)
Realized gains (loss)	(11)	(6)
Equity derivatives		
Derivative Instruments, Gain (Loss) [Line Items]		
Realized gains (loss)	(9)	(22)
Equity derivatives | OM&G		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss)	4	(5)
Realized gains (loss)	(13)	(17)
Equity derivatives | Other income, net		
Derivative Instruments, Gain (Loss) [Line Items]		
Unrealized gain (loss)	0	0
Realized gains (loss)	$ 0	$ 0

Derivatives Instruments (Credit Risk) (Narrative) (Details) $ in Millions	12 Months Ended	
	Dec. 31, 2023 CAD ($) Days	Dec. 31, 2022 CAD ($)
Credit Derivatives [Line Items]		
Total cash deposits/collateral on hand	$ 101	$ 224
Financial Asset, Past Due [Member]		
Credit Derivatives [Line Items]		
Financial assets, considered to be past due	142	131
Credit Concentration Risk		
Credit Derivatives [Line Items]		
Concentration Risk, maximum exposure	1,200	1,900
Total cash deposits/collateral on hand	310	386
Credit Concentration Risk | Receivables, net		
Credit Derivatives [Line Items]		
Fair Value, Financial assets, considered to be past due	$ 127	$ 114
Average number of days financial asset outstanding | Days	64	

Derivatives Instruments (Summary of Concentration Risk) (Details) - Credit Concentration Risk - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 1,200,000	$ 1,900,000
Receivables, net | Other accounts receivable		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 151,000	$ 585,000
% of total exposure	10.00%	25.00%
Receivables, net | Trading group		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 188,000	$ 507,000
% of total exposure	12.00%	21.00%
Receivables, net | Receivables		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 1,290,000	$ 1,982,000
% of total exposure	84.00%	83.00%
Receivables, net | Credit rating of A- or above | Trading group		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 47,000	$ 125,000
% of total exposure	3.00%	5.00%
Receivables, net | Credit rating of BBB- to BBB+ | Trading group		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 33,000	$ 75,000
% of total exposure	2.00%	3.00%
Receivables, net | Not rated | Trading group		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 108,000	$ 307,000
% of total exposure	7.00%	13.00%
Derivative Instruments (current and long-term) | Derivatives		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 240,000	$ 396,000
% of total exposure	16.00%	17.00%
Derivative Instruments (current and long-term) | Receivables and Derivatives		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 1,530,000	$ 2,378,000
% of total exposure	100.00%	100.00%
Derivative Instruments (current and long-term) | Credit rating of A- or above | Derivatives		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 138,000	$ 202,000

% of total exposure	9.00%	9.00%
Derivative Instruments (current and long-term) | Credit rating of BBB- to BBB+ | Derivatives		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 7,000	$ 8,000
% of total exposure	1.00%	0.00%
Derivative Instruments (current and long-term) | Not rated | Derivatives		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 95,000	$ 186,000
% of total exposure	6.00%	8.00%
Regulated utilities | Receivables, net		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 951,000	$ 890,000
% of total exposure	62.00%	37.00%
Regulated utilities | Receivables, net | Residential		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 476,000	$ 455,000
% of total exposure	31.00%	19.00%
Regulated utilities | Receivables, net | Commercial		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 194,000	$ 192,000
% of total exposure	13.00%	8.00%
Regulated utilities | Receivables, net | Industrial		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 84,000	$ 121,000
% of total exposure	5.00%	5.00%
Regulated utilities | Receivables, net | Other		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 103,000	$ 122,000
% of total exposure	7.00%	5.00%
Regulated utilities | Receivables, net | Cash Collateral		
Concentration Risk [Line Items]		
Concentration Risk, maximum exposure	$ 94,000	$ 0
% of total exposure	6.00%	0.00%

Derivatives Instruments (Cash Collateral Positions) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Derivative Instruments		
Cash collateral provided to others	$ 101	$ 224
Cash collateral received from others	22	112
Total fair value of these derivatives, in a liability position	$ 504	$ 1,078

FV Measurements (Classification of Fair Value of Derivatives) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Assets		
Total assets	$ 240	$ 396
Liabilities		
Total liabilities	504	1,078
Level 3		
Assets		
Total assets	34	90
Liabilities		
Total liabilities	365	826
Net assets (liabilities)	(331)	(736)
Level 3 | Regulatory deferral | Physical natural gas purchases		
Assets		
Total assets		52
Liabilities		
Total liabilities		0
Level 3 | HFT derivatives | Power swaps and physical contracts		
Assets		
Total assets		4
Liabilities		
Total liabilities		1
Level 3 | HFT derivatives | Natural gas swaps, futures, forwards and physical contracts		
Assets		
Total assets	34	34
Liabilities		
Total liabilities	365	825
Fair Value, Measurements, Recurring		
Assets		
Total assets	240	396
Liabilities		
Total liabilities	504	1,078
Net assets (liabilities)	(264)	(682)
Fair Value, Measurements, Recurring | Other		
Assets		
Total assets	22	
Liabilities		
Total liabilities	7	
Fair Value, Measurements, Recurring | FX forwards | Other		
Assets		
Total assets	18	5

Liabilities		
Total liabilities	7	23
Fair Value, Measurements, Recurring | Equity derivatives | Other		
Assets		
Total assets	4	
Liabilities		
Total liabilities		5
Fair Value, Measurements, Recurring | Regulatory deferral		
Assets		
Total assets	16	238
Liabilities		
Total liabilities	76	25
Fair Value, Measurements, Recurring | Regulatory deferral | Commodity swaps and forwards		
Assets		
Total assets	13	168
Liabilities		
Total liabilities	73	24
Fair Value, Measurements, Recurring | Regulatory deferral | FX forwards		
Assets		
Total assets	3	18
Liabilities		
Total liabilities	3	1
Fair Value, Measurements, Recurring | Regulatory deferral | Physical natural gas purchases and sales		
Assets		
Total assets		52
Fair Value, Measurements, Recurring | HFT derivatives		
Assets		
Total assets	202	153
Liabilities		
Total liabilities	421	1,025
Fair Value, Measurements, Recurring | HFT derivatives | Power swaps and physical contracts		
Assets		
Total assets	18	44
Liabilities		
Total liabilities	24	31
Fair Value, Measurements, Recurring | HFT derivatives | Natural gas swaps, futures, forwards, physical contracts		
Assets		
Total assets	184	109
Fair Value, Measurements, Recurring | HFT derivatives | Natural gas swaps, futures, forwards and physical contracts		
Liabilities		

Total liabilities	397	994
Fair Value, Measurements, Recurring | Level 1		
Assets		
Total assets	48	132
Liabilities		
Total liabilities	56	73
Net assets (liabilities)	(8)	59
Fair Value, Measurements, Recurring | Level 1 | Other		
Assets		
Total assets	4	
Liabilities		
Total liabilities	0	
Fair Value, Measurements, Recurring | Level 1 | FX forwards | Other		
Assets		
Total assets	0	0
Liabilities		
Total liabilities	0	0
Fair Value, Measurements, Recurring | Level 1 | Equity derivatives | Other		
Assets		
Total assets	4	
Liabilities		
Total liabilities		5
Fair Value, Measurements, Recurring | Level 1 | Regulatory deferral		
Assets		
Total assets	7	120
Liabilities		
Total liabilities	43	15
Fair Value, Measurements, Recurring | Level 1 | Regulatory deferral | Commodity swaps and forwards		
Assets		
Total assets	7	120
Liabilities		
Total liabilities	43	15
Fair Value, Measurements, Recurring | Level 1 | Regulatory deferral | FX forwards		
Assets		
Total assets	0	0
Liabilities		
Total liabilities	0	0
Fair Value, Measurements, Recurring | Level 1 | Regulatory deferral | Physical natural gas purchases and sales		
Assets		
Total assets		0
Fair Value, Measurements, Recurring | Level 1 | HFT derivatives		
Assets		

Total assets	37	12
Liabilities		
Total liabilities	13	53
Fair Value, Measurements, Recurring | Level 1 | HFT derivatives | Power swaps and physical contracts		
Assets		
Total assets	(5)	9
Liabilities		
Total liabilities	0	2
Fair Value, Measurements, Recurring | Level 1 | HFT derivatives | Natural gas swaps, futures, forwards, physical contracts		
Assets		
Total assets	42	3
Fair Value, Measurements, Recurring | Level 1 | HFT derivatives | Natural gas swaps, futures, forwards and physical contracts		
Liabilities		
Total liabilities	13	51
Fair Value, Measurements, Recurring | Level 2		
Assets		
Total assets	158	174
Liabilities		
Total liabilities	83	179
Net assets (liabilities)	75	(5)
Fair Value, Measurements, Recurring | Level 2 | Other		
Assets		
Total assets	18	
Liabilities		
Total liabilities	7	
Fair Value, Measurements, Recurring | Level 2 | FX forwards | Other		
Assets		
Total assets	18	5
Liabilities		
Total liabilities	7	23
Fair Value, Measurements, Recurring | Level 2 | Equity derivatives | Other		
Assets		
Total assets	0	
Liabilities		
Total liabilities		0
Fair Value, Measurements, Recurring | Level 2 | Regulatory deferral		
Assets		
Total assets	9	66
Liabilities		
Total liabilities	33	10
Fair Value, Measurements, Recurring | Level 2 | Regulatory deferral | Commodity swaps and forwards		

Assets		
Total assets	6	48
Liabilities		
Total liabilities	30	9
Fair Value, Measurements, Recurring | Level 2 | Regulatory deferral | FX forwards		
Assets		
Total assets	3	18
Liabilities		
Total liabilities	3	1
Fair Value, Measurements, Recurring | Level 2 | Regulatory deferral | Physical natural gas purchases and sales		
Assets		
Total assets		0
Fair Value, Measurements, Recurring | Level 2 | HFT derivatives		
Assets		
Total assets	131	103
Liabilities		
Total liabilities	43	146
Fair Value, Measurements, Recurring | Level 2 | HFT derivatives | Power swaps and physical contracts		
Assets		
Total assets	23	31
Liabilities		
Total liabilities	24	28
Fair Value, Measurements, Recurring | Level 2 | HFT derivatives | Natural gas swaps, futures, forwards, physical contracts		
Assets		
Total assets	108	72
Fair Value, Measurements, Recurring | Level 2 | HFT derivatives | Natural gas swaps, futures, forwards and physical contracts		
Liabilities		
Total liabilities	19	118
Fair Value, Measurements, Recurring | Level 3		
Assets		
Total assets	34	90
Liabilities		
Total liabilities	365	826
Net assets (liabilities)	(331)	(736)
Fair Value, Measurements, Recurring | Level 3 | Other		
Assets		
Total assets	0	
Liabilities		
Total liabilities	0	
Fair Value, Measurements, Recurring | Level 3 | FX forwards | Other		
Assets		

Total assets	0	0
Liabilities		
Total liabilities	0	0
Fair Value, Measurements, Recurring | Level 3 | Equity derivatives | Other		
Assets		
Total assets	0	
Liabilities		
Total liabilities		0
Fair Value, Measurements, Recurring | Level 3 | Regulatory deferral		
Assets		
Total assets	0	52
Liabilities		
Total liabilities	0	0
Fair Value, Measurements, Recurring | Level 3 | Regulatory deferral | Commodity swaps and forwards		
Assets		
Total assets	0	0
Liabilities		
Total liabilities	0	0
Fair Value, Measurements, Recurring | Level 3 | Regulatory deferral | FX forwards		
Assets		
Total assets	0	0
Liabilities		
Total liabilities	0	0
Fair Value, Measurements, Recurring | Level 3 | Regulatory deferral | Physical natural gas purchases and sales		
Assets		
Total assets		52
Fair Value, Measurements, Recurring | Level 3 | HFT derivatives		
Assets		
Total assets	34	38
Liabilities		
Total liabilities	365	826
Fair Value, Measurements, Recurring | Level 3 | HFT derivatives | Power swaps and physical contracts		
Assets		
Total assets	0	4
Liabilities		
Total liabilities	0	1
Fair Value, Measurements, Recurring | Level 3 | HFT derivatives | Natural gas swaps, futures, forwards, physical contracts		
Assets		
Total assets	34	34
Fair Value, Measurements, Recurring | Level 3 | HFT derivatives | Natural gas swaps, futures, forwards and physical contracts		

Liabilities

Total liabilities	$ 365	$ 825

FV Measurements (Change in Fair Value of Level 3 Financial Assets) (Details) $ in Millions	12 Months Ended Dec. 31, 2023 CAD ($)
Fair Value, Assets Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	$ 90
Realized gains included in fuel for generation and purchased power	(49)
Unrealized gains included in regulatory liabilities	(3)
Total realized and unrealized gains (losses) included in non-regulated operating revenues	(4)
Ending Balance	34
Regulatory deferral | Physical natural gas purchases | Energy Related derivative	
Fair Value, Assets Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	52
Realized gains included in fuel for generation and purchased power	(49)
Unrealized gains included in regulatory liabilities	(3)
Total realized and unrealized gains (losses) included in non-regulated operating revenues	0
Ending Balance	0
Not Designated as Hedging Instrument | Energy Related derivative | Non-regulated operating revenues	
Fair Value, Assets Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	90
Realized gains included in fuel for generation and purchased power	(49)
HFT derivatives | Energy Related derivative | Non-regulated operating revenues	
Fair Value, Assets Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	90
Realized gains included in fuel for generation and purchased power	(49)
Unrealized gains included in regulatory liabilities	(3)
Total realized and unrealized gains (losses) included in non-regulated operating revenues	(4)
Ending Balance	34
HFT derivatives | Power | Energy Related derivative	
Fair Value, Assets Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	4
Realized gains included in fuel for generation and purchased power	0
Unrealized gains included in regulatory liabilities	0
Total realized and unrealized gains (losses) included in non-regulated operating revenues	(4)
Ending Balance	0
HFT derivatives | Natural gas | Energy Related derivative	
Fair Value, Assets Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	

Beginning Balance	34
Realized gains included in fuel for generation and purchased power	0
Unrealized gains included in regulatory liabilities	0
Total realized and unrealized gains (losses) included in non-regulated operating revenues	0
Ending Balance	$ 34

FV Measurements (Change in Fair Value of Level 3 Financial Liabilities) (Details) - HFT derivatives - Energy Related derivative - Non-regulated operating revenues $ in Millions	12 Months Ended Dec. 31, 2023 CAD ($)
Fair Value, Liabilities Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	$ 826
Total realized and unrealized gains included in non-regulated operating revenues	(461)
Ending Balance	365
Power	
Fair Value, Liabilities Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	1
Total realized and unrealized gains included in non-regulated operating revenues	(1)
Ending Balance	0
Natural gas	
Fair Value, Liabilities Measured on Recurring Basis, Unobservable Input Reconciliation, Calculation [Roll Forward]	
Beginning Balance	825
Total realized and unrealized gains included in non-regulated operating revenues	(460)
Ending Balance	$ 365

FV Measurements (Quantitative Information About Significant Unobservable Inputs Used in Level 3 Measurements) (Details) - CAD ($)	Dec. 31, 2023	Dec. 31, 2022
Assets		
Total assets	$ 240,000,000	$ 396,000,000
Liabilities		
Total liabilities	504,000,000	1,078,000,000
Fair Value, Measurements, Recurring		
Assets		
Total assets	240,000,000	396,000,000
Liabilities		
Total liabilities	504,000,000	1,078,000,000
Net liability	264,000,000	682,000,000
Regulatory deferral | Fair Value, Measurements, Recurring		
Assets		
Total assets	16,000,000	238,000,000
Liabilities		
Total liabilities	76,000,000	25,000,000
HFT derivatives | Fair Value, Measurements, Recurring		
Assets		
Total assets	202,000,000	153,000,000
Liabilities		
Total liabilities	421,000,000	1,025,000,000
HFT derivatives | Power swaps and physical contracts | Fair Value, Measurements, Recurring		
Assets		
Total assets	18,000,000	44,000,000
Liabilities		
Total liabilities	24,000,000	31,000,000
HFT derivatives | Natural gas swaps, futures, forwards and physical contracts | Fair Value, Measurements, Recurring		
Liabilities		
Total liabilities	397,000,000	994,000,000
Level 3		
Assets		
Total assets	34,000,000	90,000,000
Liabilities		
Total liabilities	365,000,000	826,000,000
Net liability	331,000,000	736,000,000
Level 3 | Fair Value, Measurements, Recurring		

Assets		
Total assets	34,000,000	90,000,000
Liabilities		
Total liabilities	365,000,000	826,000,000
Net liability	331,000,000	736,000,000
Level 3 | Regulatory deferral | Fair Value, Measurements, Recurring		
Assets		
Total assets	0	52,000,000
Liabilities		
Total liabilities	0	0
Level 3 | Regulatory deferral | Physical natural gas purchases		
Assets		
Total assets		52,000,000
Liabilities		
Total liabilities		$ 0
Level 3 | Regulatory deferral | Range, Minimum | Physical natural gas purchases | Third-party pricing		
Liabilities		
Derivative, measurement input		5.79
Level 3 | Regulatory deferral | Range, Maximum | Physical natural gas purchases | Third-party pricing		
Liabilities		
Derivative, measurement input		31.85
Level 3 | Regulatory deferral | Weighted average | Physical natural gas purchases | Third-party pricing		
Liabilities		
Derivative, measurement input		12.27
Level 3 | HFT derivatives | Fair Value, Measurements, Recurring		
Assets		
Total assets	34,000,000	$ 38,000,000
Liabilities		
Total liabilities	365,000,000	826,000,000
Level 3 | HFT derivatives | Power swaps and physical contracts		
Assets		
Total assets		4,000,000
Liabilities		
Total liabilities		1,000,000
Level 3 | HFT derivatives | Power swaps and physical contracts | Fair Value, Measurements, Recurring		
Assets		
Total assets	0	4,000,000
Liabilities		
Total liabilities	0	1,000,000
Level 3 | HFT derivatives | Natural gas swaps, futures, forwards and physical contracts		

Assets		
Total assets	34,000,000	34,000,000
Liabilities		
Total liabilities	365,000,000	825,000,000
Level 3 | HFT derivatives | Natural gas swaps, futures, forwards and physical contracts | Fair Value, Measurements, Recurring		
Liabilities		
Total liabilities	$ 365,000,000	$ 825,000,000
Level 3 | HFT derivatives | Range, Minimum | Power swaps and physical contracts | Third-party pricing		
Liabilities		
Derivative, measurement input		43.24
Level 3 | HFT derivatives | Range, Minimum | Natural gas swaps, futures, forwards and physical contracts | Third-party pricing		
Liabilities		
Derivative, measurement input	1.27	2.45
Level 3 | HFT derivatives | Range, Maximum | Power swaps and physical contracts | Third-party pricing		
Liabilities		
Derivative, measurement input		269.10
Level 3 | HFT derivatives | Range, Maximum | Natural gas swaps, futures, forwards and physical contracts | Third-party pricing		
Liabilities		
Derivative, measurement input	16.25	33.88
Level 3 | HFT derivatives | Weighted average | Power swaps and physical contracts | Third-party pricing		
Liabilities		
Derivative, measurement input		138.79
Level 3 | HFT derivatives | Weighted average | Natural gas swaps, futures, forwards and physical contracts | Third-party pricing		
Liabilities		
Derivative, measurement input	4.85	12.01

FV Measurements (Financial Liabilities not Measured at Fair Value on Consolidated Balance Sheets) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Fair Value Measurement [Domain]		
Fair Value, Balance Sheet Grouping, Financial Statement Captions [Line Items]		
Financial assets and liabilities	$ 16,621	$ 14,670
Fair Value Measurement [Domain] | Level 1		
Fair Value, Balance Sheet Grouping, Financial Statement Captions [Line Items]		
Financial assets and liabilities	0	0
Fair Value Measurement [Domain] | Level 2		
Fair Value, Balance Sheet Grouping, Financial Statement Captions [Line Items]		
Financial assets and liabilities	16,363	14,284
Fair Value Measurement [Domain] | Level 3		
Fair Value, Balance Sheet Grouping, Financial Statement Captions [Line Items]		
Financial assets and liabilities	258	386
Carrying Amount		
Fair Value, Balance Sheet Grouping, Financial Statement Captions [Line Items]		
Financial assets and liabilities	18,365	16,318
Financial assets and liabilities	$ 16,621	$ 14,670

FV Measurements (Hybrid Notes) (Narrative) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Hybrid Instruments [Line Items]		
Hybrid Notes as a hedge of the foreign currency exposure	$ 1,200	$ 1,100
Net investment in United States dollar denominated operations		
Hybrid Instruments [Line Items]		
Hybrid Notes as a hedge of the foreign currency exposure	1,200	
After-tax foreign currency gain (loss)	$ 38	$ (97)

Related Paty Transactions (Narrative) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
NSPML | Regulated		
Related Party Transaction [Line Items]		
Purchases from Related Party	$ 163	$ 157
M&NP | Non-Regulated		
Related Party Transaction [Line Items]		
Purchases from Related Party	$ 14	$ 9

Receivables and Other Current Assets (Summary of Receivables and Other Current Assets) (Details) - CAD ($) $ in Millions	**Dec. 31, 2023**	**Dec. 31, 2022**
Receivables and Other Current Assets [Abstract]		
Customer accounts receivable - billed	$ 805	$ 1,096
Capitalized transportation capacity	358	781
Customer accounts receivable - unbilled	363	424
Prepaid expenses	105	82
Income taxes receivable	10	9
Allowance for credit losses	(15)	(17)
NMGC gas hedge settlement receivable		162
Other	191	360
Total receivables and other current assets	$ 1,817	$ 2,897

Leases (Narrative) (Details) $ in Millions, $ in Millions	12 Months Ended Dec. 31, 2023 CAD ($)	Dec. 31, 2022 CAD ($)	Oct. 31, 2023 USD ($)
Lessee, Operating Leases			
Lessee, Operating Lease, Description	The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 62 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain they will be exercised.		
Lease, Expense	$ 127	$ 138	
Variable costs for power generation facility finance leases	$ 119	131	
Lessee, Operating Lease, Existence of Option to Extend [true false]	true		
Lessee, Operating Lease, Option to Extend	The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 62 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain they will be exercised		
Lessee, Lease, Description [Line Items]			
Net Investment in Lease	$ 658	$ 638	
Renewable Natural Gas Facility [Member]			
Lessee, Lease, Description [Line Items]			
Lessor, sales-type lease, term of contract			15 years
Lessor Sales Type Lease Assumptions And Judgments Value Of Underlying Asset Amount			$ 35
Brunswick Pipeline Lease [Member]			
Lessee, Lease, Description [Line Items]			

Lessor, operating lease, term of contract	34 years
Net Investment in Lease	$ 100
Lessor lease option to extend	16 years
Minimum	
Lessee, Lease, Description [Line Items]	
Lessee, operating lease, renewal term	1 year
Maximum	
Lessee, Lease, Description [Line Items]	
Lessee, operating lease, renewal term	62 years

Leases (Lessee, Operating Leases and Additional Information) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Assets and Liabilities, Lessee		
Right-of-use asset	$ 54	$ 58
Lease liabilities, Current	3	3
Lease liabilities, Long-term	55	59
Total lease liabilities	58	62
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases	8	8
Right-of-use assets obtained in exchange for lease obligations: Operating leases	$ 1	$ 1
Weighted average remaining lease term (years)	44 years	44 years
Weighted average discount rate - operating leases	3.93%	3.98%

Leases (Lessee, Future Minimum Lease Payments Under Non-Cancellable Operating Leases) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter		
2024	$ 6	
2025	5	
2026	3	
2027	3	
2028	3	
Thereafter	111	
Minimum lease payments, Total	131	
Less imputed interest	(73)	
Total	$ 58	$ 62

Leases (Lessor, Direct Finance and Sales-Type Leases) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Net investment in direct finance and sales-type leases		
Total minimum lease payments to be received	$ 1,360	$ 1,393
Less: amounts representing estimated executory costs	(190)	(205)
Minimum lease payments receivable	1,170	1,188
Estimated residual value of leased property (unguaranteed)	183	183
Less: Credit loss reserve	(2)	0
Less: unearned finance lease income	(693)	(733)
Net investment in direct finance and sales-type leases	658	638
Principal due within one year (included in "Receivables and other current assets")	37	34
Net Investment in direct finance leases - long-term	$ 621	$ 604

Leases (Lessor, Future Minimum Lease Payments to be Received) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Leases [Abstract]		
2024	$ 97	
2025	99	
2026	98	
2027	97	
2028	96	
Thereafter	873	
Total minimum lease payments to be received	1,360	$ 1,393
Less: executory costs	(190)	(205)
Minimum lease payments receivable	$ 1,170	$ 1,188

Property, Plant and Equipment (Regulated and Non-Regulated Assets) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Property, Plant and Equipment, Net		
Total cost	$ 32,273	$ 30,576
Less: Accumulated depreciation	(9,994)	(9,574)
Total cost less: Accumulated depreciation	22,279	21,002
Construction work in progress	2,097	1,994
Property, Plant and Equipment, Net	24,376	22,996
Generation		
Property, Plant and Equipment, Net		
Total cost	$ 13,500	13,083
Generation | Range, Minimum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	3 years	
Generation | Range, Maximum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	131 years	
Transmission		
Property, Plant and Equipment, Net		
Total cost	$ 2,835	2,731
Transmission | Range, Minimum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	10 years	
Transmission | Range, Maximum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	80 years	
Distribution		
Property, Plant and Equipment, Net		
Total cost	$ 7,417	6,978
Distribution | Range, Minimum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	4 years	
Distribution | Range, Maximum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	80 years	
Gas transmission and distribution		
Property, Plant and Equipment, Net		
Total cost	$ 5,536	5,061
Gas transmission and distribution | Range, Minimum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	6 years	

Gas transmission and distribution | Range, Maximum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	92 years	
General plant and other		
Property, Plant and Equipment, Net		
Total cost	$ 2,985	$ 2,723
General plant and other | Range, Minimum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	2 years	
General plant and other | Range, Maximum		
Property, Plant and Equipment [Line Items]		
Estimated useful life	71 years	

Property, Plant and Equipment (Regulated and Non-Regulated Assets) (Narrative) (Details) - Pipeline lateral - SeaCoast Gas Transmission, LLC - General plant and other $ in Millions	12 Months Ended	
	Dec. 31, 2023 USD ($) mi	Dec. 31, 2022 USD ($)
Jointly Owned Pipleline lateral		
Jointly Owned Utility Plant, Proportionate Ownership Share	50.00%	50.00%
Length of pipeline, in miles | mi	26	
Jointly Owned Utility Plant, Gross Ownership Amount of Plant in Service	$ 27	$ 27
Jointly Owned Utility Plant, Ownership Amount of Plant Accumulated Depreciation	$ 2	$ 1

Employee Benefit Plans (Changes in Benefit Obligation and Plan Assets and Funded Status) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Defined benefit pension plans		
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")		
Benefit Obligation, Beginning Balance	$ 2,158	$ 2,624
Service cost	30	41
Plan participant contributions	6	6
Interest cost	111	80
Plan amendments	0	0
Benefits Paid	(147)	(174)
Actuarial losses (gains)	146	(480)
Settlements and curtailments	(8)	(6)
Foreign currency translation adjustment	(23)	67
Benefit Obligation, Ending Balance	2,273	2,158
Change in plan assets		
Plan Assets, Beginning Balance	2,163	2,702
Employer contributions	42	45
Plan participant contributions	6	6
Benefits paid	(147)	(174)
Actual return on assets, net of expenses	262	(489)
Settlements and curtailments	(8)	(6)
FX translation adjustment	(20)	79
Plan Assets, Ending Balance	2,298	2,163
Funded Status		
Funded status, end of year	25	5
Non-pension Benefit Plans		
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")		
Benefit Obligation, Beginning Balance	243	318
Service cost	3	4
Plan participant contributions	6	6
Interest cost	13	9
Plan amendments	(14)	0
Benefits Paid	(29)	(31)
Actuarial losses (gains)	10	(79)
Settlements and curtailments	0	0
Foreign currency translation adjustment	(5)	16
Benefit Obligation, Ending Balance	227	243
Change in plan assets		

Plan Assets, Beginning Balance	46	51
Employer contributions	23	24
Plan participant contributions	6	6
Benefits paid	(29)	(31)
Actual return on assets, net of expenses	3	(7)
Settlements and curtailments	0	0
FX translation adjustment	(1)	3
Plan Assets, Ending Balance	48	46
Funded Status		
Funded status, end of year	$ (179)	$ (197)

Employee Benefit Plans (Plans with PBO/APBO in Excess of Plan Assets) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Defined benefit pension plans		
Plans with PBO/APBO in Excess of Plan Assets		
PBO/APBO	$ 120	$ 1,006
FV of plan assets	37	914
Funded Status	(83)	(92)
Non-pension Benefit Plans		
Plans with PBO/APBO in Excess of Plan Assets		
PBO/APBO	205	221
FV of plan assets	0	0
Funded Status	$ (205)	$ (221)

Employee Benefit Plans (Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets		
ABO for the defined benefit pension plans	$ 2,172	$ 2,080
Defined benefit pension plans		
Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets		
ABO	114	111
Fair value of plan assets	37	33
Funded Status	$ (77)	$ (78)

Employee Benefit Plans (Amounts Recognized in Consolidated Balance Sheets) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Balance Sheet		
Other current liabilities	$ (23)	$ (33)
Long-term liabilities	(265)	(281)
Defined benefit pension plans		
Balance Sheet		
Other current liabilities	(5)	(13)
Long-term liabilities	(78)	(80)
Other long-term assets	108	98
AOCI, net of tax and regulatory assets	385	358
Less: Deferred income tax (expense) recovery in AOCI	(8)	(7)
Net amount recognized	402	356
Non-pension Benefit Plans		
Balance Sheet		
Other current liabilities	(18)	(20)
Long-term liabilities	(187)	(201)
Other long-term assets	26	24
AOCI, net of tax and regulatory assets	20	22
Less: Deferred income tax (expense) recovery in AOCI	(1)	(1)
Net amount recognized	$ (160)	$ (176)

Employee Benefit Plans (Amounts Recognized in AOCI and Regulatory Assets) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Change in AOCI and Regulatory Assets		
Regulatory assets	$ 3,105	$ 3,620
Defined benefit pension plans		
Change in AOCI and Regulatory Assets		
Beginning Balance	22	
Amortized in current period	1	8
Ending Balance	61	22
Actuarial losses	53	15
Past service gains	0	0
Deferred income tax expense (recovery)	8	7
AOCI, net of tax	61	22
Regulatory assets	324	336
AOCI, net of tax and regulatory assets	385	358
Defined benefit pension plans | Regulatory | Assets		
Change in AOCI and Regulatory Assets		
Beginning Balance	336	
Amortized in current period	(6)	
Current year additions (reductions)	1	
Change in FX rate	(7)	
Ending Balance	324	336
Defined benefit pension plans | Actuarial (gains) losses		
Change in AOCI and Regulatory Assets		
Beginning Balance	15	
Amortized in current period	(3)	
Current year additions (reductions)	41	
Change in FX rate	0	
Ending Balance	53	15
Defined benefit pension plans | Past service costs (gains)		
Change in AOCI and Regulatory Assets		
Beginning Balance	0	
Amortized in current period	0	
Current year additions (reductions)	0	
Change in FX rate	0	
Ending Balance	0	0
Non-pension Benefit Plans		
Change in AOCI and Regulatory Assets		
Beginning Balance	(9)	
Amortized in current period	(3)	0
Ending Balance	(9)	(9)

Actuarial losses	(8)	(10)
Past service gains	(2)	0
Deferred income tax expense (recovery)	1	1
AOCI, net of tax	(9)	(9)
Regulatory assets	29	31
AOCI, net of tax and regulatory assets	20	22
Non-pension Benefit Plans | Regulatory | Assets		
Change in AOCI and Regulatory Assets		
Beginning Balance	31	
Amortized in current period	2	
Current year additions (reductions)	(3)	
Change in FX rate	(1)	
Ending Balance	29	31
Non-pension Benefit Plans | Actuarial (gains) losses		
Change in AOCI and Regulatory Assets		
Beginning Balance	(10)	
Amortized in current period	3	
Current year additions (reductions)	(1)	
Change in FX rate	0	
Ending Balance	(8)	(10)
Non-pension Benefit Plans | Actuarial (gains) losses | Assets		
Change in AOCI and Regulatory Assets		
Beginning Balance	0	
Amortized in current period	0	
Current year additions (reductions)	(3)	
Change in FX rate	1	
Ending Balance	(2)	0
Non-pension Benefit Plans | Past service costs (gains)		
Change in AOCI and Regulatory Assets		
Beginning Balance	0	
Amortized in current period	0	
Current year additions (reductions)	(3)	
Change in FX rate	1	
Ending Balance	$ (2)	$ 0

Employee Benefit Plans (Net Periodic Benefit Cost) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Defined Benefit Plan Disclosure [Line Items]		
Expected return on plan assets	$ (2,577)	$ (2,482)
Defined benefit pension plans		
Defined Benefit Plan Disclosure [Line Items]		
Service cost	30	41
Interest cost	111	80
Expected return on plan assets	(161)	(144)
Current year amortization of: Actuarial losses	1	8
Regulatory assets (liability)	6	21
Settlement, curtailments	2	2
Net Periodic Benefit Cost, Total	(11)	8
Non-pension Benefit Plans		
Defined Benefit Plan Disclosure [Line Items]		
Service cost	3	4
Interest cost	13	9
Expected return on plan assets	(2)	0
Current year amortization of: Actuarial losses	(3)	0
Regulatory assets (liability)	(2)	2
Settlement, curtailments	0	0
Net Periodic Benefit Cost, Total	$ 9	$ 15

Employee Benefit Plans (Pension Plan Asset Allocations) (Details) - Defined benefit pension plans	Dec. 31, 2023
Cash and cash equivalents | Non-Canadian Pension Plans | Range, Minimum	
Pension Plan Asset Allocations	
Target Range at Market	0.00%
Cash and cash equivalents | Non-Canadian Pension Plans | Range, Maximum	
Pension Plan Asset Allocations	
Target Range at Market	10.00%
Short-term securities | Canadian Pension Plans | Range, Minimum	
Pension Plan Asset Allocations	
Target Range at Market	0.00%
Short-term securities | Canadian Pension Plans | Range, Maximum	
Pension Plan Asset Allocations	
Target Range at Market	10.00%
Fixed income | Canadian Pension Plans | Range, Minimum	
Pension Plan Asset Allocations	
Target Range at Market	34.00%
Fixed income | Canadian Pension Plans | Range, Maximum	
Pension Plan Asset Allocations	
Target Range at Market	49.00%
Fixed income | Non-Canadian Pension Plans | Range, Minimum	
Pension Plan Asset Allocations	
Target Range at Market	29.00%
Fixed income | Non-Canadian Pension Plans | Range, Maximum	
Pension Plan Asset Allocations	
Target Range at Market	49.00%
Equities: Canadian | Canadian Pension Plans | Range, Minimum	
Pension Plan Asset Allocations	
Target Range at Market	7.00%
Equities: Canadian | Canadian Pension Plans | Range, Maximum	
Pension Plan Asset Allocations	
Target Range at Market	17.00%
Equities: Non-Canadian | Canadian Pension Plans | Range, Minimum	
Pension Plan Asset Allocations	
Target Range at Market	35.00%
Equities: Non-Canadian | Canadian Pension Plans | Range, Maximum	
Pension Plan Asset Allocations	
Target Range at Market	59.00%
Equities: Non-Canadian | Non-Canadian Pension Plans | Range, Minimum	
Pension Plan Asset Allocations	
Target Range at Market	48.00%

Equities: Non-Canadian | Non-Canadian Pension Plans | Range, Maximum

Pension Plan Asset Allocations	
Target Range at Market	68.00%

Employee Benefit Plans (Fair Value of Plan Assets) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022	Dec. 31, 2021
Defined benefit pension plans			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ 2,298	$ 2,163	$ 2,702
Total			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ 2,298	$ 2,163	
Percentage	100.00%	100.00%	
Total | Cash and cash equivalents			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ 40	$ 70	
Percentage	2.00%	3.00%	
Total | Net in-transits			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ (9)	$ (70)	
Percentage	0.00%	(3.00%)	
Total | Canadian equity			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ 96	$ 87	
Percentage	4.00%	4.00%	
Total | US equity			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ 141	$ 233	
Percentage	6.00%	11.00%	
Total | Other equity			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ 112	$ 186	
Percentage	5.00%	8.00%	
Total | Government			
Classification of the methodology used by the Company to fair value its investments			
Fair Value of Plan Assets	$ 172	$ 104	
Percentage	8.00%	5.00%	
Total | Corporate			

Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 90	$ 83
Percentage	4.00%	4.00%
Total | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 9	$ 14
Percentage	0.00%	1.00%
Total | Mutual funds		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 50	$ 68
Percentage	2.00%	3.00%
Total | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 5	$ (3)
Percentage	0.00%	0.00%
Total | Open-ended investments measured at NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 1,006	$ 790
Percentage	44.00%	36.00%
Total | Common collective trusts measured at NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 586	$ 601
Percentage	25.00%	28.00%
NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 1,592	$ 1,391
NAV | Cash and cash equivalents		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Net in-transits		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Canadian equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0

NAV | US equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Other equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Government		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Corporate		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Mutual funds		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
NAV | Open-ended investments measured at NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	1,006	790
NAV | Common collective trusts measured at NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	586	601
Level 1		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	440	577
Level 1 | Cash and cash equivalents		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	40	70
Level 1 | Net in-transits		

Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	(9)	(70)
Level 1 | Canadian equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	96	87
Level 1 | US equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	141	233
Level 1 | Other equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	112	186
Level 1 | Government		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 1 | Corporate		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 1 | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	4	3
Level 1 | Mutual funds		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	50	68
Level 1 | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	6	0
Level 1 | Open-ended investments measured at NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 1 | Common collective trusts measured at NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2		

Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	266	195
Level 2 | Cash and cash equivalents		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2 | Net in-transits		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2 | Canadian equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2 | US equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2 | Other equity		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2 | Government		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	172	104
Level 2 | Corporate		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	90	83
Level 2 | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	5	11
Level 2 | Mutual funds		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2 | Other		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	(1)	(3)
Level 2 | Open-ended investments measured at NAV		

Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	0	0
Level 2 | Common collective trusts measured at NAV		
Classification of the methodology used by the Company to fair value its investments		
Fair Value of Plan Assets	$ 0	$ 0

Employee Benefit Plans (Expected Cash Flows for Defined Benefit Pension and Other Post-Retirement Benefit Plans) (Details) $ in Millions	Dec. 31, 2023 CAD ($)
Defined benefit pension plans	
Expected employer contributions	
Expected employer contributions, 2024	$ 34
Expected benefit payments	
Expected benefit payments, 2024	172
Expected benefit payments, 2025	163
Expected benefit payments, 2026	166
Expected benefit payments, 2027	171
Expected benefit payments, 2028	173
Expected benefit payments, 2029 - 2033	890
Non-pension Benefit Plans	
Expected employer contributions	
Expected employer contributions, 2024	19
Expected benefit payments	
Expected benefit payments, 2024	21
Expected benefit payments, 2025	21
Expected benefit payments, 2026	21
Expected benefit payments, 2027	21
Expected benefit payments, 2028	20
Expected benefit payments, 2029 - 2033	$ 95

Employee Benefit Plans (Assumptions Used in Accounting for Defined Benefit Pension and Other Post-Retirement Benefit Plans) (Details)	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Defined benefit pension plans		
Benefit obligation - December 31:		
Discount rate - past service	4.89%	5.33%
Discount rate - future service	4.88%	5.34%
Rate of compensation increase	3.87%	3.62%
Health care trend - initial (next year)	0.00%	0.00%
Health care trend - ultimate	0.00%	0.00%
Benefit cost for year ended December 31:		
Discount rate - past service	5.33%	3.05%
Discount rate - future service	5.34%	3.18%
Expected long-term return on plan assets	6.56%	6.07%
Rate of compensation increase	3.62%	3.31%
Health care trend - initial (next year)	0.00%	0.00%
Health care trend - ultimate	0.00%	0.00%
Non-pension Benefit Plans		
Benefit obligation - December 31:		
Discount rate - past service	4.89%	5.31%
Discount rate - future service	4.89%	5.32%
Rate of compensation increase	3.85%	3.61%
Health care trend - initial (next year)	6.04%	5.40%
Health care trend - ultimate	3.76%	3.77%
Health care trend - year ultimate reached	2043	2043
Benefit cost for year ended December 31:		
Discount rate - past service	5.31%	2.81%
Discount rate - future service	5.32%	2.92%
Expected long-term return on plan assets	2.16%	1.32%
Rate of compensation increase	3.61%	3.29%
Health care trend - initial (next year)	5.40%	5.09%
Health care trend - ultimate	3.77%	3.77%
Health care trend - year ultimate reached	2043	2042

Employee Benefit Plans (Narrative) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Defined-Benefit Plans, information		
Defined Benefit Plan, Description	Emera maintains a number of contributory defined-benefit ("DB") and defined-contribution ("DC") 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, and Grand Bahama Island.	
Defined Benefit Plan, Plan Assets, Investment Policy and Strategy, Description	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.	
Defined Benefit Plan, Plan Assets, Expected Long-term Rate-of-Return, Description	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.	
Defined Benefit Plan, Expected Return on Plan Assets	$ 2,577	$ 2,482
Contribution Amount	$ 45	41
Plan assets recognition period	5 years	
Defined benefit pension plans		
Defined-Benefit Plans, information		
Defined Benefit Plan, Expected Return on Plan Assets	$ 161	144
Non-pension Benefit Plans		
Defined-Benefit Plans, information		
Defined Benefit Plan, Expected Return on Plan Assets	$ 2	$ 0

Goodwill (Change in Goodwill) (Details)	12 Months Ended		
	Dec. 31, 2023 USD ($)	Dec. 31, 2023 CAD ($)	Dec. 31, 2022 CAD ($)
Goodwill [Roll Forward]			
Balance, January 1		$ 6,012,000,000	$ 5,696,000,000
Change in FX rate		(141,000,000)	389,000,000
GBPC impairment charge		0	(73,000,000)
Balance, December 31		5,871,000,000	6,012,000,000
Tampa Electric and PGS			
Goodwill [Roll Forward]			
GBPC impairment charge	$ 0		
NMGC			
Goodwill [Roll Forward]			
GBPC impairment charge		$ 0	
GBPC			
Goodwill [Roll Forward]			
Balance, January 1			
GBPC impairment charge			$ (73,000,000)
Balance, December 31			

Short-Term Debt (Short-Term Debt and Related Weighted-Average Interest Rates) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 1,433	$ 2,726
Weighted average interest rate	5.95%	5.01%
Advances on revolving credit and term facilities | TECO Finance		
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 245	$ 481
Weighted average interest rate	6.54%	5.47%
Non-revolving term facilities | Emera Inc.		
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 796	$ 796
Weighted average interest rate	6.07%	5.19%
Bank indebtedness | Emera Inc.		
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 9	$ 0
Weighted average interest rate	0.00%	0.00%
Advances on revolving credit facilities | TEC		
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 277	$ 1,380
Weighted average interest rate	5.68%	5.00%
Advances on revolving credit facilities | PGS		
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 73	$ 0
Weighted average interest rate	6.36%	0.00%
Advances on revolving credit facilities | NMGC		
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 25	$ 59
Weighted average interest rate	6.46%	5.15%
Advances on revolving credit facilities | GBPC		
Short-term debt and the related weighted-average interest rates		
Short-term debt	$ 8	$ 10
Weighted average interest rate	5.54%	5.25%

Short-Term Debt (Short-Term Revolving and Non-Revolving Credit Facilities, Outstanding Borrowings and Available Capacity) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Total available capacity	$ 2,773	$ 3,155
Total advances under available facilities	1,436	2,735
Available capacity under existing agreements	$ 1,337	420
Revolving credit facility | TEC		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2026	
Total available capacity	$ 401	1,084
Revolving credit facility | TECO Energy/TECO Finance		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2026	
Total available capacity	$ 0	542
Revolving credit facility | TECO Finance		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2026	
Total available capacity	$ 529	0
Revolving credit facility | PGS		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2028	
Total available capacity	$ 331	0
Revolving credit facility | NMGC		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2026	
Total available capacity	$ 165	169
Revolving credit facility II | TEC		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2024	
Total available capacity	$ 265	542
Revolving credit facility III | TEC		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		

Maturity	2024	
Total available capacity	$ 265	0
Revolving credit facility III | Other		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Total available capacity	$ 17	18
Term credit facility | TEC		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2024	
Non-revolving term loan | Emera Inc.		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2024	
Total available capacity	$ 400	400
Non-revolving term loan II | Emera Inc.		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Maturity	2024	
Total available capacity	$ 400	400
Advances under revolving credit and term facilities		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Total advances under available facilities	1,433	2,731
Letters of credit issued within the credit facilities		
Short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity		
Total advances under available facilities	$ 3	$ 4

Short-Term Debt (Narrative) (Details) $ in Millions, $ in Millions	Dec. 16, 2023 CAD ($)	Dec. 15, 2023	Dec. 01, 2023 USD ($)	Nov. 24, 2023 USD ($)	Jun. 30, 2023 CAD ($)	Jun. 29, 2023	Apr. 03, 2023 USD ($)	Mar. 01, 2023 USD ($)	Dec. 31, 2023 CAD ($)	Dec. 31, 2022 CAD ($)
Line of Credit Facility [Line Items]										
Weighted average interest rate									5.95%	5.01%
Line of Credit Facility, Maximum Borrowing Capacity									$ 2,773	$ 3,155
Revolving credit facility | TEC										
Line of Credit Facility [Line Items]										
Line of Credit Facility, Maximum Borrowing Capacity									401	1,084
Revolving credit facility | NMGC										
Line of Credit Facility [Line Items]										
Line of Credit Facility, Maximum Borrowing Capacity									165	169
Revolving credit facility | TECO Energy/ TECO Finance										
Line of Credit Facility [Line Items]										
Line of Credit Facility, Maximum Borrowing Capacity									0	542
Revolving credit facility | TECO Finance										
Line of Credit Facility [Line Items]										
Line of Credit Facility, Maximum Borrowing Capacity									529	0
Revolving credit facility | Peoples Gas System [Member]										
Line of Credit Facility [Line Items]										
Line of Credit Facility, Maximum Borrowing Capacity									331	0
Revolving credit facility | Peoples Gas System [Member] | Gas Utilities and Infrastructure										
Line of Credit Facility [Line Items]										
Line of Credit Facility, Maximum Borrowing Capacity			$ 250							
Line of Credit Facility, Expiration Date			Dec. 01, 2028							
Available increase in borrowing capacity			$ 100							
Revolving credit facility II | TEC										
Line of Credit Facility [Line Items]										
Line of Credit Facility, Maximum Borrowing Capacity									265	542

Revolving credit facility II | TEC | Florida Electric Utility [Member]							
Line of Credit Facility [Line Items]							
Line of Credit Facility, Maximum Borrowing Capacity				$ 200			
Line of Credit Facility, Expiration Date				Apr. 01, 2024			
Debt term				364 days			
Revolving credit facility III | TEC							
Line of Credit Facility [Line Items]							
Line of Credit Facility, Maximum Borrowing Capacity						$ 265	$ 0
Revolving credit facility III | TEC | Florida Electric Utility [Member]							
Line of Credit Facility [Line Items]							
Line of Credit Facility, Maximum Borrowing Capacity					$ 200		
Line of Credit Facility, Expiration Date					Feb. 28, 2024		
Debt term					364 days		
Non-revolving term facilities | TEC | Florida Electric Utility [Member]							
Line of Credit Facility [Line Items]							
Line of Credit Facility, Maximum Borrowing Capacity			$ 400				
Line of Credit Facility, Expiration Date			Dec. 13, 2023				
Non-revolving term facilities | Emera Inc.							
Line of Credit Facility [Line Items]							
Weighted average interest rate						6.07%	5.19%
Line of Credit Facility, Maximum Borrowing Capacity						$ 400	$ 400
Non-revolving term facilities | Emera Inc. | Other Segments [Member]							
Line of Credit Facility [Line Items]							
Line of Credit Facility, Maximum Borrowing Capacity	$ 400						
Debt Instrument, Maturity Date	Dec. 16, 2024	Dec. 16, 2023					
Non-revolving term loan II | Emera Inc.							

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<tr><td>Line of Credit Facility [Line Items]</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>Non-revolving term loan II | Emera Inc. | Other Segments [Member]</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>Line of Credit Facility, Maximum Borrowing Capacity</td><td>$ 400</td><td></td><td></td><td></td></tr>
<tr><td>Debt Instrument, Maturity Date</td><td>Aug. 02, 2024</td><td>Aug. 02, 2023</td><td></td><td></td></tr>
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Other Current Liabilities (Components of Other Current Liabilities) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Other Current Liabilities		
Accrued charges	$ 172	$ 174
Nova Scotia Cap-and-Trade Program provision	0	172
Accrued interest on long-term debt	107	97
Pension and post-retirement liabilities	23	33
Sales and other taxes payable	11	14
Income taxes payable	2	9
Other	112	80
Other current liabilities, Total	$ 427	$ 579

Long-Term Debt (Summary of Long-Term Debt, Revolving Credit Facilities, Outstanding Borrowings and Available Capacity) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Debt Instrument [Line Items]		
Debt issuance costs	$ (125)	$ (126)
Amount due within one year	(676)	(574)
Long Term Debt, Adjustments	(801)	(698)
Long-Term Debt	17,689	15,744
Interest expense	109	110
Emera		
Debt Instrument [Line Items]		
Long-term debt	2,552	2,528
NMGC		
Debt Instrument [Line Items]		
Long-term debt	672	629
NSPI		
Debt Instrument [Line Items]		
Long-term debt	3,886	3,546
ECI		
Debt Instrument [Line Items]		
Long-term debt	422	449
TECO Energy		
Debt Instrument [Line Items]		
Fair market value adjustment	$ 0	$ 2
Bankers acceptances | SOFR loans | Emera		
Debt Instrument [Line Items]		
Interest Rate Terms	Variable	Variable
Maturity	2027	
Long-term debt	$ 465	$ 403
Unsecured fixed rate notes | Emera		
Debt Instrument [Line Items]		
Weighted average interest rate	4.84%	2.90%
Maturity	2030	
Long-term debt	$ 500	$ 500
Unsecured fixed rate notes | Emera Finance		
Debt Instrument [Line Items]		
Maturity	2024 - 2046	
Fixed to floating subordinated notes | Emera		
Debt Instrument [Line Items]		
Weighted average interest rate	6.75%	6.75%

Maturity	2076	
Long-term debt	$ 1,587	$ 1,625
Unsecured senior notes | Emera Finance		
Debt Instrument [Line Items]		
Weighted average interest rate	3.65%	3.65%
Long-term debt	$ 3,637	$ 3,725
Fixed rate notes and bonds | TEC		
Debt Instrument [Line Items]		
Weighted average interest rate	4.61%	4.15%
Maturity	2024 - 2051	
Long-term debt	$ 5,654	$ 4,341
Fixed rate notes and bonds | PGS		
Debt Instrument [Line Items]		
Weighted average interest rate	5.63%	3.78%
Maturity	2028 - 2053	
Long-term debt	$ 1,223	$ 772
Fixed rate notes and bonds | NMGC		
Debt Instrument [Line Items]		
Weighted average interest rate	3.78%	3.11%
Maturity	2026 - 2051	
Long-term debt	$ 642	$ 521
Fixed rate notes and bonds | NMGI		
Debt Instrument [Line Items]		
Weighted average interest rate	3.64%	3.64%
Maturity	2024	
Long-term debt	$ 198	$ 203
Discount notes | NSPI		
Debt Instrument [Line Items]		
Interest Rate Terms	Variable	Variable
Maturity	2024 - 2027	
Long-term debt	$ 721	$ 881
Medium term fixed rate notes | NSPI		
Debt Instrument [Line Items]		
Weighted average interest rate	5.13%	5.14%
Maturity	2025 - 2097	
Long-term debt	$ 3,165	$ 2,665
Senior secured credit facility | EBP		
Debt Instrument [Line Items]		
Interest Rate Terms	Variable	Variable
Maturity	2026	
Long-term debt	$ 246	$ 249
Amortizing fixed rate notes | ECI		
Debt Instrument [Line Items]		
Weighted average interest rate	4.00%	3.97%

Maturity	2026	
Long-term debt	$ 79	$ 100
Secured senior notes | ECI		
Debt Instrument [Line Items]		
Interest Rate Terms	Variable	Variable
Maturity	2027	
Long-term debt	$ 75	$ 86
Secured fixed rate senior notes | ECI		
Debt Instrument [Line Items]		
Weighted average interest rate	3.09%	3.06%
Maturity	2024 - 2029	
Long-term debt	$ 84	$ 142
Non-revolving term facility, floating rate | NMGC		
Debt Instrument [Line Items]		
Interest Rate Terms	Variable	Variable
Maturity	2024	
Long-term debt	$ 30	$ 108
Non-revolving term facility, floating rate | ECI		
Debt Instrument [Line Items]		
Interest Rate Terms	Variable	Variable
Maturity	2025	
Long-term debt	$ 29	$ 30
Non-revolving term facility, fixed rate | ECI		
Debt Instrument [Line Items]		
Weighted average interest rate	2.15%	2.05%
Maturity	2025 - 2027	
Long-term debt	$ 155	$ 91

Long-Term Debt (Revolving Credit Facilities, Outstanding Borrowings and Available Capacity) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 2,773	$ 3,155
Use of available facilities	1,890	1,408
Available capacity under existing agreements	1,337	420
Revolving credit facility		
Debt Instrument [Line Items]		
Available capacity under existing agreements	3,197	2,219
Available capacity under existing agreements	1,307	811
Advances on the revolving credit facility	50	
Revolving credit facility | Emera		
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 900	900
Maturity	June 2027	
Revolving credit facility | TEC		
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 657	0
Maturity	December 2026	
Revolving credit facility | NSPI		
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 800	800
Maturity	December 2027	
Revolving credit facility | ECI		
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 10	11
Maturity	October 2024	
Non-revolving credit facility | Emera		
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 400	0
Maturity	February 2024	
Non-revolving credit facility | NSPI		
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 400	400
Maturity	July 2024	
Non-revolving credit facility | NMGC		
Debt Instrument [Line Items]		
Available capacity under existing agreements	$ 30	108
Maturity	March 2024	
Borrowings under credit facilities		

Debt Instrument [Line Items]		
Use of available facilities	$ 1,884	1,396
Letters of credit issued within the credit facilities		
Debt Instrument [Line Items]		
Use of available facilities	$ 6	$ 12

Long-Term Debt (Significant Covenants) (Details)	Dec. 31, 2023
Maximum	
Debt Instrument [Line Items]	
Debt to capital ratio	0.70
Syndicated credit facilities	
Debt Instrument [Line Items]	
Debt to capital ratio	0.57

Long-Term Debt (Long-Term Debt Maturities) (Details) $ in Millions	Dec. 31, 2023 CAD ($)
Subsidiaries	
Debt Instrument [Line Items]	
2024	$ 1,670
2025	264
2026	3,047
2027	666
2028	525
Thereafter	12,318
Total, long-term debt maturities, including capital lease obligations	18,490
Emera	
Debt Instrument [Line Items]	
2024	199
2025	0
2026	1,587
2027	266
2028	0
Thereafter	500
Total, long-term debt maturities, including capital lease obligations	2,552
Emera US Finance LP	
Debt Instrument [Line Items]	
2024	397
2025	0
2026	992
2027	0
2028	0
Thereafter	2,248
Total, long-term debt maturities, including capital lease obligations	3,637
Tampa Electric	
Debt Instrument [Line Items]	
2024	397
2025	0
2026	0
2027	0
2028	0
Thereafter	5,257
Total, long-term debt maturities, including capital lease obligations	5,654
PGS	
Debt Instrument [Line Items]	
2024	0
2025	0

2026	0
2027	0
2028	463
Thereafter	760
Total, long-term debt maturities, including capital lease obligations	1,223
NMGC	
Debt Instrument [Line Items]	
2024	30
2025	0
2026	93
2027	0
2028	0
Thereafter	549
Total, long-term debt maturities, including capital lease obligations	672
NMGI	
Debt Instrument [Line Items]	
2024	198
2025	0
2026	0
2027	0
2028	0
Thereafter	0
Total, long-term debt maturities, including capital lease obligations	198
NSPI	
Debt Instrument [Line Items]	
2024	398
2025	125
2026	40
2027	323
2028	0
Thereafter	3,000
Total, long-term debt maturities, including capital lease obligations	3,886
EBP	
Debt Instrument [Line Items]	
2024	0
2025	0
2026	246
2027	0
2028	0
Thereafter	0
Total, long-term debt maturities, including capital lease obligations	246
ECI	
Debt Instrument [Line Items]	
2024	51

2025	139
2026	89
2027	77
2028	62
Thereafter	4
Total, long-term debt maturities, including capital lease obligations	$ 422

Long-Term Debt (Narrative) (Details) $ in Millions, $ in Millions	Feb. 16, 2024	Jan. 30, 2024 USD ($)	Dec. 19, 2023 USD ($)	Oct. 19, 2023 USD ($)	Aug. 18, 2023 CAD ($)	May 24, 2023 USD ($)	May 02, 2023 CAD ($)	Mar. 24, 2023 CAD ($)	12 Months Ended Dec. 31, 2023 CAD ($)	12 Months Ended Dec. 31, 2022 CAD ($)
Debt Instrument [Line Items]										
Available capacity under existing agreements									$ 2,773	$ 3,155
Repayment of long-term debt									$ 151	$ 367
Senior unsecured bonds due March 1, 2029 | TEC | Subsequent event | Florida Electric Utility [Member]										
Debt Instrument [Line Items]										
Debt instrument, face amount		$ 500								
Maturity date		Mar. 01, 2029								
Stated interest rate		4.90%								
5-year credit facility | TEC | Subsequent event | Florida Electric Utility [Member]										
Debt Instrument [Line Items]										
Repayment of long-term debt		$ 497								
Debt term		5 years								
Unsecured notes due November 15, 2032 and March 24, 2053 | NSPI | Canadian Electric Utilities										
Debt Instrument [Line Items]										
Debt instrument, face amount								$ 500		
Unsecured notes due November 15, 2032 | NSPI | Canadian Electric Utilities										
Debt Instrument [Line Items]										
Debt instrument, face amount								$ 300		
Maturity date								Nov. 15, 2032		
Stated interest rate								4.95%		
Unsecured notes due March 24, 2053 | NSPI | Canadian Electric Utilities										
Debt Instrument [Line Items]										
Debt instrument, face amount								$ 200		

Maturity date				Mar. 24, 2053
Stated interest rate				5.36%
Senior notes due December 19, 2028, December 19, 2033 and December 19, 2053 | PGS | Gas Utilities and Infrastructure [Member]				
Debt Instrument [Line Items]				
Debt instrument, face amount	$ 925			
Senior notes due December 19, 2028 | PGS | Gas Utilities and Infrastructure [Member]				
Debt Instrument [Line Items]				
Debt instrument, face amount	$ 350			
Maturity date	Dec. 19, 2028			
Stated interest rate	5.42%			
Senior notes due December 19, 2033 | PGS | Gas Utilities and Infrastructure [Member]				
Debt Instrument [Line Items]				
Debt instrument, face amount	$ 350			
Maturity date	Dec. 19, 2033			
Stated interest rate	5.63%			
Senior notes due December 19, 2053 | PGS | Gas Utilities and Infrastructure [Member]				
Debt Instrument [Line Items]				
Debt instrument, face amount	$ 225			
Maturity date	Dec. 19, 2053			
Stated interest rate	5.94%			
Senior unsecured notes due October 19, 2033 | NMGC | Gas Utilities and Infrastructure [Member]				
Debt Instrument [Line Items]				
Debt instrument, face amount		$ 100		
Maturity date		Oct. 19, 2033		
Stated interest rate		6.36%		
Non-revolving term loan due May 24, 2028 | GBPC | Other Electric Utilities [Member]				
Debt Instrument [Line Items]				
Debt instrument, face amount			$ 28	

Maturity date			May 24, 2028	
Stated interest rate			4.00%	
Non-revolving term facility due February 19, 2025 | Emera				
Debt Instrument [Line Items]				
Debt instrument, face amount		$ 400		
Maturity date		Feb. 19, 2024		
Non-revolving term facility due February 19, 2025 | Emera | Subsequent event				
Debt Instrument [Line Items]				
Maturity date	Feb. 19, 2025			
Senior unsecured notes due May 2, 2030 | Emera				
Debt Instrument [Line Items]				
Debt instrument, face amount				$ 500
Maturity date				May 02, 2030
Stated interest rate				4.84%

Asset Retirement Obligation (Change in Asset Retirement Obligations) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Change in ARO		
Balance, January 1	$ 174	$ 174
Accretion included in depreciation expense	9	9
Change in FX rate	(1)	3
Additions	0	1
Accretion deferred to regulatory asset (included in PP&E)	18	1
Liabilities settled	(8)	(1)
Revisions in estimated cash flows	0	(13)
Balance, December 31	$ 192	$ 174

Commitments and Contingencies (Summary of Contractual Commitments) (Details) $ in Millions	12 Months Ended Dec. 31, 2023 CAD ($) MW	Dec. 31, 2022 CAD ($)
Recorded Unconditional Purchase Obligation [Line Items]		
2024	$ 2,698	
2025	1,217	
2026	856	
2027	747	
2028	690	
Thereafter	6,253	
Contractual Commitments	12,461	
Other commitments		
Commitment	1,772	$ 2,273
Revenue, Remaining Performance Obligation, Amount	$ 488	$ 450
Nalcor Energy		
Other commitments		
Long-term Purchase Commitment, Period	50 years	
Nalcor Energy | Equity contributions true ups		
Recorded Unconditional Purchase Obligation [Line Items]		
Contractual Commitments	$ 240	
SeaCoast Gas Transmission, LLC | PGS		
Other commitments		
Revenue, Remaining Performance Obligation, Amount	$ 134	
Maritime Link Project		
Other commitments		
Long-term Purchase Commitment, Period	38 years	
Maritime Link Project | NSPML		
Other commitments		
Approved base rate	$ 1,800	
Maritime Link Project | NSPI		
Other commitments		
Commitment	$ 164	
LIL		
Other commitments		
Capacity of electricity transmission project (MW) | MW	700	
Transportation		
Recorded Unconditional Purchase Obligation [Line Items]		
2024	$ 696	
2025	495	
2026	405	
2027	388	
2028	338	

Thereafter	2,597
Contractual Commitments	4,919
Purchased power	
Recorded Unconditional Purchase Obligation [Line Items]	
2024	274
2025	249
2026	263
2027	312
2028	312
Thereafter	3,435
Contractual Commitments	4,845
Fuel, gas supply and storage	
Recorded Unconditional Purchase Obligation [Line Items]	
2024	556
2025	215
2026	62
2027	0
2028	5
Thereafter	0
Contractual Commitments	838
Capital projects	
Recorded Unconditional Purchase Obligation [Line Items]	
2024	778
2025	111
2026	70
2027	1
2028	0
Thereafter	0
Contractual Commitments	960
Equity Method Investments	
Recorded Unconditional Purchase Obligation [Line Items]	
2024	240
2025	0
2026	0
2027	0
2028	0
Thereafter	0
Contractual Commitments	240
Other Commitment [Member]	
Recorded Unconditional Purchase Obligation [Line Items]	
2024	154
2025	147
2026	56
2027	46

2028	35
Thereafter	221
Contractual Commitments	$ 659

Commitments and Contingencies (Legal Proceedings) (Narrative) (Details) - Dec. 31, 2023 $ in Millions, $ in Millions	CAD ($)	USD ($)
Prime Rate [Member] | Tampa Electric		
Loss Contingencies [Line Items]		
Loss Contingency, Estimate of Possible Loss	$ 15	$ 11

Commitments and Contingencies (Guarantees and Letters of Credit) (Narrative) (Details) $ in Millions, $ in Millions	Dec. 31, 2023 USD ($)	Dec. 31, 2023 CAD ($)	Dec. 31, 2022 USD ($)	Dec. 31, 2022 CAD ($)
Nova Scotia Power Inc. [Member]				
Guarantor Obligations [Line Items]				
Guaranty Liabilities	$ 104		$ 119	
Letters of Credit Outstanding, Amount		$ 56		$ 63
TECO Energy				
Guarantor Obligations [Line Items]				
Letters of Credit Outstanding, Amount	13			
Guarantor Obligations, Maximum Exposure, Undiscounted	13			
TECO Energy | SeaCoast Gas Transmission, LLC				
Guarantor Obligations [Line Items]				
Guarantor Obligations, Maximum Exposure, Undiscounted	45			
ECI				
Guarantor Obligations [Line Items]				
Guaranty Liabilities	66			
Payment Guarantee | SeaCoast Gas Transmission, LLC				
Guarantor Obligations [Line Items]				
Letters of Credit Outstanding, Amount	27			
Surety Bonds				
Guarantor Obligations [Line Items]				
Letters of Credit Outstanding, Amount	$ 103		$ 145	

Commitments and Contingencies (Collaborative Arrangements) (Narrative) (Details) - Jointly Owned Electricity Generation Plant - NSPI - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Collaborative Arrangement and Arrangement Other than Collaborative [Line Items]		
Regulated fuel for generation and purchased power	$ 8	$ 12
Operating, maintenance and general (OM&G)	$ 3	$ 3

Cumulative Preferred Stock (Summary of Cumulative Preferred Stock Authorized) (Details) - CAD ($) $ / shares in Units, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Class of Stock [Line Items]		
Issued and Outstanding	58,000,000	58,000,000
Net Proceeds	$ 1,422	$ 1,422
Series A Preferred Stock		
Class of Stock [Line Items]		
Annual Dividend Per Share	$ 0.5456	
Preferred Stock, Redemption Price Per Share	$ 25.00	
Issued and Outstanding	4,866,814	4,866,814
Net Proceeds	$ 119	$ 119
Series B Preferred Stock		
Class of Stock [Line Items]		
Preferred Stock, Redemption Price Per Share	$ 25.00	
Issued and Outstanding	1,133,186	1,133,186
Net Proceeds	$ 28	$ 28
Preferred Stock Dividend Payment Rate Variable	Floating	
Series C Preferred Stock		
Class of Stock [Line Items]		
Annual Dividend Per Share	$ 1.6085	
Preferred Stock, Redemption Price Per Share	$ 25.00	
Issued and Outstanding	10,000,000	10,000,000
Net Proceeds	$ 245	$ 245
Series E Preferred Stock		
Class of Stock [Line Items]		
Annual Dividend Per Share	$ 1.1250	
Preferred Stock, Redemption Price Per Share	$ 25.00	
Issued and Outstanding	5,000,000	5,000,000
Net Proceeds	$ 122	$ 122
Series F Preferred Stock		
Class of Stock [Line Items]		
Annual Dividend Per Share	$ 1.0505	
Preferred Stock, Redemption Price Per Share	$ 25.00	
Issued and Outstanding	8,000,000	8,000,000
Net Proceeds	$ 195	$ 195
Series H Preferred Stock		
Class of Stock [Line Items]		
Annual Dividend Per Share	$ 1.5810	
Preferred Stock, Redemption Price Per Share	$ 25.00	
Issued and Outstanding	12,000,000	12,000,000

Net Proceeds	$ 295	$ 295
Series J Preferred Stock		
Class of Stock [Line Items]		
Annual Dividend Per Share	$ 1.0625	
Preferred Stock, Redemption Price Per Share	$ 25.00	
Issued and Outstanding	8,000,000	8,000,000
Net Proceeds	$ 196	$ 196
Series L Preferred Stock		
Class of Stock [Line Items]		
Annual Dividend Per Share	$ 1.1500	
Preferred Stock, Redemption Price Per Share	$ 26.00	
Issued and Outstanding	9,000,000	9,000,000
Net Proceeds	$ 222	$ 222

Cumulative Preferred Stock (Characteristics of the First Preferred Shares) (Details) - 12 months ended Dec. 31, 2023 - $ / shares	Total	Total
Series A Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	4.40%	
Current Annual Dividend		$ 0.5456
Earliest Redemption and/or Conversion Option Date	August 15, 2025	August 15, 2025
Redemption Value	$ 25.00	$ 25.00
Preferred Stock, Conversion Basis	Right to Convert on a one for one basis	Right to Convert on a one for one basis
Conversion of Stock, Type of Stock Converted	Series B	Series B
Series A Preferred Stock | Minimum		
Class of Stock [Line Items]		
Initial Yield	1.84%	
Series C Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	4.10%	
Current Annual Dividend		$ 1.6085
Earliest Redemption and/or Conversion Option Date	August 15, 2028	August 15, 2028
Redemption Value	$ 25.00	$ 25.00
Preferred Stock, Conversion Basis	Right to Convert on a one for one basis	Right to Convert on a one for one basis
Conversion of Stock, Type of Stock Converted	Series D	Series D
Series C Preferred Stock | Minimum		
Class of Stock [Line Items]		
Initial Yield	2.65%	
Series C Preferred Stock | Prior To August 15, 2028		
Class of Stock [Line Items]		
Current Annual Dividend	$ 1.1802	
Series F Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	4.202%	
Current Annual Dividend		$ 1.0505
Earliest Redemption and/or Conversion Option Date	February 15, 2025	February 15, 2025
Redemption Value	$ 25.00	$ 25.00
Preferred Stock, Conversion Basis	Right to Convert on a one for one basis	Right to Convert on a one for one basis
Conversion of Stock, Type of Stock Converted	Series G	Series G
Series F Preferred Stock | Minimum		
Class of Stock [Line Items]		
Initial Yield	2.63%	

Series B Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	2.393%	
Earliest Redemption and/or Conversion Option Date	August 15, 2025	August 15, 2025
Redemption Value	$ 25.00	$ 25.00
Preferred Stock, Conversion Basis	Right to Convert on a one for one basis	Right to Convert on a one for one basis
Conversion of Stock, Type of Stock Converted	Series A	Series A
Series B Preferred Stock | Minimum		
Class of Stock [Line Items]		
Initial Yield	1.84%	
Series H Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	4.90%	
Current Annual Dividend		$ 1.5810
Earliest Redemption and/or Conversion Option Date	August 15, 2028	August 15, 2028
Redemption Value	$ 25.00	$ 25.00
Preferred Stock, Conversion Basis	Right to Convert on a one for one basis	Right to Convert on a one for one basis
Conversion of Stock, Type of Stock Converted	Series I	Series I
Series H Preferred Stock | Minimum		
Class of Stock [Line Items]		
Initial Yield	4.90%	
Series H Preferred Stock | Prior To August 15, 2028		
Class of Stock [Line Items]		
Current Annual Dividend	$ 1.2250	
Series J Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	4.25%	
Current Annual Dividend		$ 1.0625
Earliest Redemption and/or Conversion Option Date	May 15, 2026	May 15, 2026
Redemption Value	$ 25.00	$ 25.00
Right to Convert on a one for one basis	Series K	Series K
Series J Preferred Stock | Minimum		
Class of Stock [Line Items]		
Initial Yield	4.25%	
Series E Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	4.50%	
Current Annual Dividend		$ 1.1250
Redemption Value	$ 25.00	25.00
Series L Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	4.60%	

Current Annual Dividend		$ 1.1500
Earliest Redemption and/or Conversion Option Date	November 15, 2026	November 15, 2026
Redemption Value	$ 26.00	$ 26.00
Series L Preferred Stock | On Or After November 15, 2026 to November 15, 2027		
Class of Stock [Line Items]		
Redemption Value	26.00	26.00
Series L Preferred Stock | After November 15, 2027 To November 15, 2030		
Class of Stock [Line Items]		
Preferred Stock, Redemption Price, Annual Decrease	0.25	0.25
Series L Preferred Stock | After November 15, 2030		
Class of Stock [Line Items]		
Redemption Value	25.00	25.00
Series D Preferred Stock		
Class of Stock [Line Items]		
Redemption Value	25.00	25.00
Series D Preferred Stock | After August 15, 2028		
Class of Stock [Line Items]		
Redemption Value	25.50	25.50
Series G Preferred Stock		
Class of Stock [Line Items]		
Redemption Value	25	25
Series G Preferred Stock | After February 15, 2025		
Class of Stock [Line Items]		
Redemption Value	$ 25.5	25.5
Series I Preferred Stock		
Class of Stock [Line Items]		
Initial Yield	2.54%	
Redemption Value	$ 25	25
Series I Preferred Stock | After August 15, 2028		
Class of Stock [Line Items]		
Redemption Value	$ 25.5	$ 25.5

Cumulative Preferred Stock (Narrative) (Details)	12 Months Ended Dec. 31, 2023
First Preferred Shares	
Class of Stock [Line Items]	
Preferred Stock Dividend Preference Or Restrictions	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 are deducted on the Consolidated Statements of Income before arriving at “Net income attributable to common shareholders” and shown on the Consolidated Statement of Changes in 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.

Non-Controlling Interest in Subsidiaries (Components of Non-Controlling Interest) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Noncontrolling Interest [Line Items]		
Stockholders' Equity Attributable to Noncontrolling Interest	$ 14	$ 14
GBPC		
Noncontrolling Interest [Line Items]		
Noncontrolling Interest, Amount Represented by Preferred Stock	$ 14	$ 14

Non-Controlling Interest in Subsidiaries (Preferred Shares of GBPC) (Details) - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Noncontrolling Interest [Line Items]		
Number of shares issued and outstanding	58,000,000	58,000,000
Non-voting Cumulative Redeemable Variable Perpetual Preferred Shares | GBPC		
Noncontrolling Interest [Line Items]		
Preferred Stock, Shares Authorized	10,000	
Number of shares issued and outstanding	10,000	10,000
Outstanding as at December 31	$ 14	$ 14

Non-Controlling Interest in Subsidiaries (Narrative) (Details) - GBPC	12 Months Ended Dec. 31, 2023 $ / shares
Noncontrolling Interest [Line Items]	
Preferred Stock, Dividend Payment Terms	6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually
Preferred Stock, Redemption Terms	The preferred shares are redeemable by GBPC after June 17, 2021
Non-voting Cumulative Redeemable Variable Perpetual Preferred Shares	
Noncontrolling Interest [Line Items]	
Preferred Stock, Redemption Price Per Share	$ 1,000
Non-voting Cumulative Redeemable Variable Perpetual Preferred Shares | USD preferred shares	
Noncontrolling Interest [Line Items]	
Debt Instrument, Interest Rate, Stated Percentage	6.00%

Supplementary Information to Consolidated Statements of Cash Flows (Summary of Supplementary Information to Consolidated Statement of Cash Flows) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Changes in non-cash working capital		
Inventory	$ (31)	$ (214)
Receivables and other current assets	653	(636)
Accounts payable	(538)	423
Other current liabilities	(179)	193
Total non-cash working capital	(95)	(234)
Supplemental disclosure of cash paid:		
Interest	930	699
Income Taxes	43	67
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	271	237
Reclassification of short-term debt to long-term debt	657	0
Reclassification of long-term debt to short-term debt	0	500
Decrease in accrued capital expenditures	(19)	(13)
Supplemental disclosure of operating activities:		
Net change in short-term regulatory assets and liabilities	123	(157)
January 2023 Settlement Of NMGC Gas Hedges [Member]		
Changes in non-cash working capital		
Receivables and other current assets	162	(162)
Nova Scotia Cap-And-Trade Program [Member]		
Changes in non-cash working capital		
Other current liabilities	$ (166)	$ 172

Stock-Based Compensation (Employee Common Share Purchase Plan and Common Shareholders Dividend Reinvestment and Share Purchase Plan) (Narrative) (Details) shares in Millions	12 Months Ended		
	Dec. 31, 2023 CAD ($) shares	Dec. 31, 2023 USD ($) shares	Dec. 31, 2022 CAD ($)
Employee Common Share Purchase Plan			
Employee Stock Ownership Plan (ESOP) Disclosures [Line Items]			
Employee Common Share Purchase Plan, Description	Eligible employees may participate in the ECSPP. As of December 31, 2023, 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 reinvestment of dividends for all participants except where prohibited by law.	Eligible employees may participate in the ECSPP. As of December 31, 2023, 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 reinvestment of dividends for all participants except where prohibited by law.	
Defined Contribution Plan, Minimum Annual Contributions Per Employee, Amount	$ 25		
Defined Contribution Plan, Maximum Annual Contributions Per Employee, Amount	$ 20,000	$ 15,000	
Defined Contribution Plan, Employer Matching Contribution, Percent of Match	20.00%	20.00%	
Compensation cost for shares issued	$ 3,000,000		$ 3,000,000
Dividend Reinvestment Plan			
Employee Stock Ownership Plan (ESOP) Disclosures [Line Items]			
Employee Common Share Purchase Plan, Description	The Company also has a Common Shareholders DRIP, which provides an opportunity for	The Company also has a Common Shareholders DRIP, which provides an opportunity for	

	shareholders residing in Canada 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 2023.	shareholders residing in Canada 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 2023.	
Maximum aggregate number of common shares reserved for issuance | shares	7	7	
Discount from Market Price, Purchase Date			2.00%
Dividend Reinvestment Plan | Maximum			
Employee Stock Ownership Plan (ESOP) Disclosures [Line Items]			
Discount from Market Price, Purchase Date	5.00%	5.00%	

Stock-Based Compensation (Narrative) (Details) $ / shares in Units, $ in Thousands, shares in Millions, $ in Millions	12 Months Ended			
	Dec. 31, 2023 CAD ($) $ / shares shares	Dec. 31, 2022 CAD ($) $ / shares shares	Dec. 31, 2022 USD ($)	Dec. 31, 2021
Stock option plan, Additional information				
Percentage of outstanding stock maximum	10.00%			
Dividend Reinvestment Plan				
Stock option plan, Additional information				
Maximum aggregate number of common shares reserved for issuance | shares	7.0			
Share Unit Plans				
Maximum aggregate number of common shares reserved for issuance | shares	7.0			
DSU Plan				
Share Unit Plans				
Cash payments made during the year	$ 3,000	$ 8,000		
Employee Stock Option Plan				
Stock option plan, Additional information				
Maximum term	10 years			
Maximum aggregate number of common shares reserved for issuance | shares	6.0	6.0		
Terms of award	P10Y			
Share Unit Plans				
Maximum aggregate number of common shares reserved for issuance | shares	6.0	6.0		
Share Unit Plans				
Stock option plan, Additional information				
Maximum aggregate number of common shares reserved for issuance | shares	2.0	2.7		

Share Unit Plans				
Maximum aggregate number of common shares reserved for issuance | shares	2.0	2.7		
First Anniversary | DSU Plan | Executive and senior management				
Stock option plan, Additional information				
Vesting rights, percentage	25.00%			
First Anniversary | DSU Plan | Executive and senior management | Minimum				
Stock option plan, Additional information				
Vesting rights, percentage	50.00%			
Vesting period after date of retirement | Employee Stock Option Plan				
Stock option plan, Additional information				
Vesting period				27 months
Vesting period after termination without just cause or death | Employee Stock Option Plan				
Stock option plan, Additional information				
Vesting period		6 months	6 months	6 months
Vesting period after termination for just cause or resignation | Employee Stock Option Plan				
Stock option plan, Additional information				
Vesting period		60 days	60 days	60 days
Stock Option Plan				
Stock option plan, Additional information				
Share-based payment award, description	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 price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded before the date on which			

	the option is granted. The maximum aggregate number of shares issuable under this plan is 14.7 million shares. As at December 31, 2023, Emera was in compliance with this requirement. Stock options granted in 2021 and prior vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. Stock options granted in 2022 and thereafter vest in 20 per cent increments on the first, second, third, fourth and fifth 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.	
Maximum aggregate number of common shares reserved for issuance | shares	14.7	
Vesting rights	The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued.	
Percentage of outstanding stock maximum	5.00%	
Policy for issuing shares upon exercise	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.	
Cash received for options exercised	$ 6,000	$ 9,000
Total intrinsic value of options exercised	$ 2,000	$ 4,000
Exercise price range, lower range limit | $ / shares	$ 32.35	$ 32.35
Exercise price range, upper range limit | $ / shares	$ 60.03	$ 60.03
Fair value assumptions, method used	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.	
Share Unit Plans		
Compensation cost recognized for employee and director	$ 2,000	$ 2,000
Maximum aggregate number of common shares reserved for issuance | shares	14.7	
Stock Option Plan, Granted 2021 | First Anniversary		

Stock option plan, Additional information			
Vesting rights, percentage			25.00%
Stock Option Plan, Granted 2021 | Second Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage			25.00%
Stock Option Plan, Granted 2021 | Third Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage			25.00%
Stock Option Plan, Granted 2021 | Fourth Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage			25.00%
Stock Option Plan, Granted 2022 | First Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage	20.00%	20.00%	
Stock Option Plan, Granted 2022 | Second Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage	20.00%	20.00%	
Stock Option Plan, Granted 2022 | Third Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage	20.00%	20.00%	
Stock Option Plan, Granted 2022 | Fourth Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage	20.00%	20.00%	
Stock Option Plan, Granted 2022 | Fifth Anniversary			
Stock option plan, Additional information			
Vesting rights, percentage	20.00%	20.00%	
Share Unit Plans | Share Unit Plans			

Stock option plan, Additional information		
Share-based payment award, description	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		
Share Unit Plans		
Compensation cost recognized for employee and director	$ 2,000	$ 6,000
Tax expense related to compensation costs for share units realized	1,000	2,000
Deferred Share Unit Plans | Employee		
Share Unit Plans		
Share Unit Plans: Aggregate intrinsic value	36,000	33,000
Deferred Share Unit Plans | Director		
Share Unit Plans		
Share Unit Plans: Aggregate intrinsic value	$ 37,000	34,000
Deferred Share Unit Plans | Share Unit Plans | DSU Plan		
Share Unit Plans		
Deferred share unit plan, description	When short-term 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 made in cash. In addition, special DSU awards may be made from time to time by the Management Resources and Compensation Committee ("MRCC"), to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.	

Deferred Share Unit Plans | Share Unit Plans | DSU Plan | Executive and senior management		
Share Unit Plans		
Deferred share unit plan, description	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.	
Deferred Share Unit Plans | Share Unit Plans | DSU Plan | Director		
Share Unit Plans		
Deferred share unit plan, description	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.	
Performance Share Unit Plan		
Stock option plan, Additional information		
Award service period	3 years	
Share Unit Plans		
Tax expense related to compensation costs for share units realized	$ 3,000	5,000
Cash payments made during the year	19,000	24,000

Performance Share Unit Plan | Employee			
Share Unit Plans			
Share Unit Plans: Aggregate intrinsic value	$ 41,000	40,000	
Performance Share Unit Plan | Share Unit Plans			
Stock option plan, Additional information			
Share-based payment award, description	Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the 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. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.		
Compensation cost recognized for stock options	$ 11,000	18,000	
Restricted Share Unit Plan			
Stock option plan, Additional information			
Award service period	3 years		
Share Unit Plans			
Tax expense related to compensation costs for share units realized	$ 3,000		$ 2
Share Unit Plans: Aggregate intrinsic value	32,000		
Cash payments made during the year	$ 10,000		
Restricted Share Unit Plan | Employee			
Share Unit Plans			
Share Unit Plans: Aggregate intrinsic value		30,000	
Restricted Share Unit Plan | Share Unit Plans			

Stock option plan, Additional information		
Share-based payment award, description	Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the 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. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.	
Compensation cost recognized for stock options	$ 10,000	$ 9,000

Stock-Based Compensation (Weighted Average Fair Values per Stock Option and Assumptions for Options Granted) (Details) - $ / shares	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Stock-Based Compensation [Abstract]		
Weighted average FV per option	$ 6.32	$ 5.35
Expected term	5 years	5 years
Risk-free interest rate	3.53%	1.79%
Expected dividend yield	5.05%	4.55%
Expected volatility	20.07%	18.87%

Stock-Based Compensation (Summary of Stock Option Information) (Details) - CAD ($) $ / shares in Units, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Total Options, Number of Options		
Total Options: Number of Options, Exercised	(620,000)	(600,000)
Non-Vested Options: Weighted average exercise price per share		
Non-Vested Options: Weighted average exercise price per share, Granted	$ 6.32	$ 5.35
Stock option plan, Additional information		
Non-Vested options: Unrecognized compensation	$ 5	$ 4
Non-vested options: Weighted average recognition period	3 years	3 years
Vested Options: Weighted average remaining term	5 years	5 years
Vested Options: Aggregate intrinsic value	$ 8	$ 10
Vested Options: Fair value	$ 2	$ 2
Employee Stock Option Plan		
Total Options, Number of Options		
Total Options: Number of Options, Outstanding, Beginning Balance	2,853,879	
Granted	483,100	
Total Options: Number of Options, Exercised	(146,475)	
Total Options: Number of Options, Forfeited	(94,900)	
Total Options: Number of Options, Outstanding, Ending Balance	3,095,604	2,853,879
Total Options: Number of Options, Options exercisable	1,842,349	
Total Options, Weighted average exercise price per share		
Total Options: Weighted average exercise price per share, Outstanding, Beginning Balance	$ 50.41	
Total Options: Weighted average exercise price per share, Granted	54.64	
Total Options: Weighted average exercise price per share, Exercised	43.94	
Total Options: Weighted average exercise price per share, Forfeited	56.32	
Total Options: Weighted average exercise price per share, Outstanding, Ending Balance	51.20	$ 50.41
Total Options: Weighted average exercise price per share, Options exercisable	$ 48.39	
Non-Vested Options, Number of Options		
Non-Vested Options: Number of Options, Outstanding, Beginning Balance	1,348,400	
Granted	483,100	
Non-Vested Options: Number of Options, Vested	526,620	
Non-Vested Options: Number of options, Forfeited	(51,625)	
Non-Vested Options: Number of Options, Ending Balance	1,253,255	1,348,400
Non-Vested Options: Weighted average exercise price per share		
Non-Vested Options: Weighted average exercise price per share, Outstanding, Beginning Balance	$ 4.08	
Non-Vested Options: Weighted average exercise price per share, Granted	6.32	
Non-Vested Options: Weighted average exercise price per share, Vested	3.58	

Non-Vested Options: Weighted average exercise price per share, Forfeited	3.61	
Non-Vested Options: Weighted average exercise price per share, Outstanding, Ending Balance	$ 5.17	$ 4.08

Stock-Based Compensation (Summary of Activity Related to Employee and Director Deferred Share Units) (Details) - DSU Plan - Deferred Share Unit Plans	12 Months Ended Dec. 31, 2023 $ / shares shares
Employee	
Share Unit Plans: Units	
Share Unit Plans: Outstanding, Beginning Balance | shares	627,223
Share Unit Plans: Granted including DRIP | shares	85,740
Share Unit Plans: Outstanding and exercisable, Ending Balance | shares	712,963
Share Unit Plans: Weighted Average Grant Date Fair Value	
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding, Beginning Balance | $ / shares	$ 41.55
Share Unit Plans: Weighted Average Grant Date Fair Value: Granted including DRIP | $ / shares	47.66
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding and exercisable, Ending Balance | $ / shares	$ 42.29
Director	
Share Unit Plans: Units	
Share Unit Plans: Outstanding, Beginning Balance | shares	664,258
Share Unit Plans: Granted including DRIP | shares	117,893
Share Unit Plans: Exercised | shares	(53,093)
Share Unit Plans: Outstanding and exercisable, Ending Balance | shares	729,058
Share Unit Plans: Weighted Average Grant Date Fair Value	
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding, Beginning Balance | $ / shares	$ 45.83
Share Unit Plans: Weighted Average Grant Date Fair Value: Granted including DRIP | $ / shares	49.99
Share Unit Plans: Weighted Average Grant Date Fair Value: Exercised | $ / shares	49.39
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding and exercisable, Ending Balance | $ / shares	$ 46.24

Stock-Based Compensation (Summary of Activity Related to Employee Performance Share Units) (Details) - Performance Share Unit Plan - Employee - CAD ($) $ / shares in Units, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Share Unit Plans: Units		
Share Unit Plans: Outstanding, Beginning Balance	690,446	
Share Unit Plans: Granted including DRIP	386,261	
Share Unit Plans: Exercised	(323,155)	
Share Unit Plans: Forfeited	(10,187)	
Share Unit Plans: Outstanding and exercisable, Ending Balance	743,365	
Share Unit Plans: Weighted Average Grant Date Fair Value		
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding, Beginning Balance	$ 56.24	
Share Unit Plans: Weighted Average Grant Date Fair Value: Granted including DRIP	52.71	
Share Unit Plans: Weighted Average Grant Date Fair Value: Exercised	54.62	
Share Unit Plans: Weighted Average Grant Date Fair Value: Forfeited	55.15	
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding and exercisable, Ending Balance	$ 55.13	
Share Unit Plans: Aggregate intrinsic value		
Share Unit Plans: Aggregate intrinsic value	$ 41.0	$ 40.0

Stock-Based Compensation (Summary of Activity Related to Employee Restricted Share Units) (Details) - Restricted Share Unit Plan - CAD ($) $ / shares in Units, $ in Millions	12 Months Ended	
	Dec. 31, 2023	Dec. 31, 2022
Share Unit Plans: Aggregate intrinsic value		
Share Unit Plans: Aggregate intrinsic value	$ 32	
Employee		
Share Unit Plans: Units		
Share Unit Plans: Outstanding, Beginning Balance	508,468	
Share Unit Plans: Granted including DRIP	236,537	
Share Unit Plans: Exercised	(171,537)	
Share Unit Plans: Forfeited	(10,827)	
Share Unit Plans: Outstanding and exercisable, Ending Balance	562,641	
Share Unit Plans: Weighted Average Grant Date Fair Value		
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding, Beginning Balance	$ 56.25	
Share Unit Plans: Weighted Average Grant Date Fair Value: Granted including DRIP	52.07	
Share Unit Plans: Weighted Average Grant Date Fair Value: Exercised	54.62	
Share Unit Plans: Weighted Average Grant Date Fair Value: Forfeited	54.76	
Share Unit Plans: Weighted Average Grant Date Fair Value: Outstanding and exercisable, Ending Balance	$ 55.01	
Share Unit Plans: Aggregate intrinsic value		
Share Unit Plans: Aggregate intrinsic value		$ 30

Variable Interest Entities (Summary of Material Unconsolidated Variable Interest Entities) (Details) - NSPML - NSPML - CAD ($) $ in Millions	Dec. 31, 2023	Dec. 31, 2022
Variable Interest Entity [Line Items]		
Equity Method Investment, Underlying Equity in Net Assets	$ 489	$ 501
Maximum exposure to loss	$ 6	$ 6