EMERA INCORPORATED

Consolidated Financial Statements

December 31, 2022 and 2021

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 23, 2023

"Scott Balfour"
President and Chief Executive Officer

"Gregory Blunden"
Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion

We have audited the consolidated financial statements of Emera Incorporated (the "Company"), which comprise the Consolidated Balance Sheets as at December 31, 2022 and 2021, and the Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2022 and 2021, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

Basis for opinion

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

Key audit matters

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

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

	Accounting for the effects of rate regulation
Key Audit Matter	As disclosed in note 7 of the consolidated financial statements, the Company has \$3.6 billion in regulatory assets and \$2.3 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 to customers through future rates.

How Our Audit Addressed the Key Audit Matter

We performed audit procedures that included, amongst others, assessing the Company’s evaluation of the probability of future recovery for regulatory assets, 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 in future rates based on the regulator’s treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company’s calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

Fair value measurement of derivative financial instruments

Key Audit Matter

Held-for-trading (“HFT”) derivative assets of $429 million and liabilities of $1,301 million, disclosed in note 15 to the consolidated financial statements, are measured at fair value. The Company recognized $64 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 fair value of the contracts. In determining the fair value of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials. These assumptions have a significant impact on the fair value of the HFT derivatives.

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

Other information

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

- Management's Discussion and Analysis

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

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

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

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

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

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

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

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

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

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

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

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

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

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

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

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

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

/s/ Ernst & Young LLP
Chartered Professional Accountants

Halifax, Canada
February 23, 2023

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, 2022 and 2021, 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, 2022 and 2021, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2022, in conformity with United States generally accepted accounting principles.

Basis for Opinion

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

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

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

Critical Audit Matters

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

Accounting for the effects of rate regulation

Description of the Matter	As disclosed in note 7 of the consolidated financial statements, the Company has $3.6 billion in regulatory assets and $2.3 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, 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 to customers through future rates.
How We Addressed the Matter in Our Audit	We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, 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 in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

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

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

Halifax, Canada
February 23, 2023

Emera Incorporated
Consolidated Statements of Income

For the millions of dollars (except per share amounts)		Year ended December 31 **2022**		2021
Operating revenues				
Regulated electric	**$**	**5,473**	$	4,665
Regulated gas		**1,681**		1,261
Non-regulated		**434**		(161)
Total operating revenues (note 6)		**7,588**		5,765
Operating expenses				
Regulated fuel for generation and purchased power		**2,171**		1,763
Regulated cost of natural gas		**800**		472
Operating, maintenance and general expenses ("OM&G")		**1,596**		1,368
Provincial, state, and municipal taxes		**367**		330
Depreciation and amortization		**952**		902
Impairment charge (note 22)		**73**		-
Total operating expenses		**5,959**		4,835
Income from operations		**1,629**		930
Income from equity investments (note 8)		**129**		143
Other income, net (note 9)		**145**		93
Interest expense, net		**709**		611
Income before provision for income taxes		**1,194**		555
Income tax expense (recovery) (note 10)		**185**		(6)
Net income		**1,009**		561
Non-controlling interest in subsidiaries		**1**		1
Preferred stock dividends		**63**		50
Net income attributable to common shareholders	**$**	**945**	$	510
Weighted average shares of common stock outstanding (in millions) (note 12)				
Basic		**266**		257
Diluted		**266**		258
Earnings per common share (note 12)				
Basic	**$**	**3.56**	$	1.98
Diluted	**$**	**3.55**	$	1.98
Dividends per common share declared	**$**	**2.6775**	$	2.5750

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 **2022**	2021
Net income	**$ 1,009**	$ 561
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	**629**	(42)
Unrealized (losses) gains on net investment hedges (2) (3)	**(97)**	5
Cash flow hedges		
Net derivative gains (4)	**-**	18
Less: reclassification adjustment for gains included in income	**(2)**	(1)
Net effects of cash flow hedges	**(2)**	17
Unrealized losses on available-for-sale investment	**(1)**	-
Net change in unrecognized pension and post-retirement benefit obligation (5)	**24**	124
Other comprehensive income (6)	**553**	104
Comprehensive income	**1,562**	665
Comprehensive income attributable to non-controlling interest	**1**	1
Comprehensive Income of Emera Incorporated	**$ 1,561**	$ 664

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

1) Net of tax expense of $7 million for the year ended December 31, 2022 (2021 – $5 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 recovery of $6 million for the year ended December 31, 2022 (2021 – $1 million expense).
4) Net of tax recovery of $1 million for the year ended December 31, 2022 (2021 – $6 million expense).
5) Net of tax expense of $1 million for the year ended December 31, 2022 (2021 – $2 million expense).
6) Net of tax expense of $1 million for the year ended December 31, 2022 (2021 – $14 million expense).

Emera Incorporated
Consolidated Balance Sheets

As at millions of dollars		December 31 2022		December 31 2021
Assets				
Current assets				
Cash and cash equivalents	**$**	**310**	$	394
Restricted cash (note 32)		**22**		23
Inventory (note 14)		**769**		538
Derivative instruments (notes 15 and 16)		**296**		195
Regulatory assets (note 7)		**602**		253
Receivables and other current assets (note 18)		**2,897**		1,733
		4,896		3,136
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $9,574 and $8,739, respectively (note 20)		**22,996**		20,353
Other assets				
Deferred income taxes (note 10)		**237**		295
Derivative instruments (notes 15 and 16)		**100**		106
Regulatory assets (note 7)		**3,018**		2,313
Net investment in direct finance and sales type leases (note 19)		**604**		503
Investments subject to significant influence (note 8)		**1,418**		1,382
Goodwill (note 22)		**6,012**		5,696
Other long-term assets (note 32)		**461**		460
		11,850		10,755
Total assets	**$**	**39,742**	$	34,244
Liabilities and Equity				
Current liabilities				
Short-term debt (note 23)	**$**	**2,726**	$	1,742
Current portion of long-term debt (note 25)		**574**		462
Accounts payable		**2,025**		1,485
Derivative instruments (notes 15 and 16)		**888**		533
Regulatory liabilities (notes 7 and 32)		**495**		290
Other current liabilities (note 24)		**579**		366
		7,287		4,878
Long-term liabilities				
Long-term debt (note 25)		**15,744**		14,196
Deferred income taxes (note 10)		**2,196**		1,868
Derivative instruments (notes 15 and 16)		**190**		149
Regulatory liabilities (note 7)		**1,778**		1,765
Pension and post-retirement liabilities (note 21)		**281**		370
Other long-term liabilities (notes 8 and 26)		**825**		868
		21,014		19,216
Equity				
Common stock (note 11)		**7,762**		7,242
Cumulative preferred stock (note 28)		**1,422**		1,422
Contributed surplus		**81**		79
Accumulated other comprehensive income ("AOCI') (note 13)		**578**		25
Retained earnings		**1,584**		1,348
Total Emera Incorporated equity		**11,427**		10,116
Non-controlling interest in subsidiaries (note 29)		**14**		34
Total equity		**11,441**		10,150
Total liabilities and equity	**$**	**39,742**	$	34,244

Commitments and contingencies (note 27)

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard"
Chair of the Board

"Scott Balfour"
President and Chief Executive Officer

Emera Incorporated
Consolidated Statements of Cash Flows

For the millions of dollars	Year ended December 31 **2022**	2021
Operating activities		
Net income	**$ 1,009**	$ 561
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**959**	915
Income from equity investments, net of dividends	**(61)**	(69)
Allowance for equity funds used during construction	**(52)**	(61)
Deferred income taxes, net	**152**	(37)
Net change in pension and post-retirement liabilities	**(48)**	(23)
Fuel adjustment mechanism ("FAM")	**(162)**	(166)
Net change in fair value of derivative instruments	**206**	404
Net change in regulatory assets and liabilities	**(471)**	(176)
Net change in capitalized transportation capacity	**(445)**	(107)
Impairment charge	**73**	-
Other operating activities, net	**(13)**	96
Changes in non-cash working capital (note 30)	**(234)**	(152)
Net cash provided by operating activities	**913**	1,185
Investing activities		
Additions to PP&E	**(2,596)**	(2,359)
Other investing activities	**27**	27
Net cash used in investing activities	**(2,569)**	(2,332)
Financing activities		
Change in short-term debt, net	**1,028**	(155)
Proceeds from short-term debt with maturities greater than 90 days	**544**	640
Repayment of short-term debt with maturities greater than 90 days	**(680)**	(377)
Proceeds from long-term debt, net of issuance costs	**784**	2,554
Retirement of long-term debt	**(367)**	(1,660)
Net proceeds under committed credit facilities	**511**	82
Issuance of common stock, net of issuance costs	**277**	317
Issuance of preferred stock, net of issuance costs (note 28)	**-**	416
Dividends on common stock	**(472)**	(443)
Dividends on preferred stock	**(63)**	(50)
Other financing activities	**(7)**	(13)
Net cash provided by financing activities	**1,555**	1,311
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**16**	(1)
Net increase (decrease) in cash, cash equivalents, and restricted cash	**(85)**	163
Cash, cash equivalents, and restricted cash, beginning of year	**417**	254
Cash, cash equivalents, and restricted cash, end of year	**$ 332**	$ 417
Cash, cash equivalents, and restricted cash consists of:		
Cash	**$ 302**	$ 237
Short-term investments	**8**	157
Restricted cash	**22**	23
Cash, cash equivalents, and restricted cash	**$ 332**	$ 417

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, 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 ($2.6775/share)	**-**	**-**	**-**	**-**	**(709)**	**-**	**(709)**
Issued under the at-the-market program ("ATM"), net of after-tax issuance costs	**248**	**-**	**-**	**-**	**-**	**-**	**248**
Issued under the Dividend Reinvestment Program ("DRIP"), net of discount	**238**	**-**	**-**	**-**	**-**	**-**	**238**
Senior management stock options exercised and Employee Share Purchase Plan	**34**	**-**	**2**	**-**	**-**	**-**	**36**
Disposal of non-controlling interest of Dominica Electricity Services Ltd ("Domlec")	**-**	**-**	**-**	**-**	**-**	**(20)**	**(20)**
Other	**-**	**-**	**-**	**-**	**-**	**(1)**	**(1)**
Balance, December 31, 2022	**$ 7,762**	**$ 1,422**	**$ 81**	**$ 578**	**$ 1,584**	**$ 14**	**$ 11,441**
Balance, December 31, 2020	$ 6,705	$ 1,004	$ 79	$ (79)	$ 1,495	$ 34	$ 9,238
Net income of Emera Inc.	-	-	-	-	560	1	561
Other comprehensive income, net of tax expense of $14 million	-	-	-	104	-	-	104
Issuance of preferred stock, net of after-tax issuance costs	-	418	-	-	-	-	418
Dividends declared on preferred stock (note 28)	-	-	-	-	(50)	-	(50)
Dividends declared on common stock ($2.5750/share)	-	-	-	-	(657)	-	(657)
Issued under the ATM, net of after-tax issuance costs	284	-	-	-	-	-	284
Issued under the DRIP, net of discount	215	-	-	-	-	-	215
Senior management stock options exercised and Employee Share Purchase Plan	38	-	-	-	-	-	38
Other	-	-	-	-	-	(1)	(1)
Balance, December 31, 2021	$ 7,242	$ 1,422	$ 79	$ 25	$ 1,348	$ 34	$ 10,150

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

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, 2022, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric, a vertically integrated regulated electric utility, serving approximately 827,000 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 541,000 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, owned and constructed by Nalcor Energy. ENL's two investments are:
    - a 100 per cent investment in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion (including allowance for funds used during construction ("AFUDC")) transmission project; and
    - a 31.9 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador.

- Gas Utilities and Infrastructure, which includes:
  - Peoples Gas System ("PGS"), a regulated gas distribution utility, serving approximately 468,000 customers across Florida;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 545,000 customers in New Mexico;
  - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas ("LNG") from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership, which expires in 2034;
  - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company in Florida; and
  - a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline that transports natural gas throughout markets in Atlantic Canada and the northeastern United States.

- 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 133,000 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 includes:
    - Emera Energy, which consists of:
        - Emera Energy Services ("EES"), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
        - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; and
        - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 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;
    - Emera Technologies LLC, a wholly owned technology company focused on finding ways to deliver renewables and resilient energy to customers;
    - Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States; and
    - Other investments.

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 entity that most significantly impacts its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera has an investment in a VIE but is not deemed the primary beneficiary, the VIE is accounted for using the equity method. 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 the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations ("ARO"), and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.

Regulatory Matters

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

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are converted to 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 the 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 regulator and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly or bi-monthly. At the end of each reporting period, the electricity and gas delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of 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 the terms of the contract are satisfied and are presented on a net basis, reflecting the nature of the contractual relationships with customers and suppliers.

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

Other non-regulated revenues are recorded when obligations under 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.

Leases

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

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

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

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

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

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

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

Franchise Fees and Gross Receipts

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

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

Property, Plant and Equipment

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

Goodwill

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

If the Company performs the qualitative assessment and determines that it is more likely than not that its fair value is less than its carrying amount, or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, an impairment loss is recorded. Management estimates the fair value of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach is applied using a discounted cash flow analysis which relies on management’s best estimate of the reporting units’ projected cash flows. The analysis includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the reporting unit’s residual cash flows. The discount rate used is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. When using the market approach, management estimates fair value based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the fair value include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting units' net operating loss (“NOL”) and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera’s reporting units.

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

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

Income Taxes and Investment Tax Credits

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

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

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

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

Derivatives and Hedging Activities

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

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

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

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

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

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

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

Cash, Cash Equivalents and Restricted Cash

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

Receivables and Allowance for Credit Losses

Utility customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date. The Company 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 that the weighted-average cost will be recovered in future customer rates.

Asset Impairment

Long-Lived Assets:

Emera assesses whether there has been an impairment of long-lived assets and intangibles when a triggering event occurs, such as a significant market disruption or sale of a business.

The assessment involves comparing the undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated fair value. The Company's assumptions relating to future results of operations or other recoverable amounts, are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which consider external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

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

Equity Method Investments:

The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the fair value of these investments to their carrying values, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists, and it is determined to be other-than-temporary, a charge is recognized in earnings equal to the amount the carrying value exceeds the investment's fair value. No impairment of equity method investments was required in either 2022 or 2021.

Financial Assets:

Equity investments, other than those accounted for under the equity method, are measured at fair value, with changes in fair value recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable fair values are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments. No impairment of financial assets was required in either 2022 or 2021.

Asset Retirement Obligations

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

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

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

Cost of Removal

Tampa Electric, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO COR represent funds received from customers through depreciation rates to cover estimated future non-legally required COR of 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 fair value-based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are initially measured at fair value and re-measured at fair value at each reporting date, with the change in liability recognized in income.

Employee Benefits

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCI or regulatory assets. The components of net periodic benefit cost other than the service cost component are included in "Other income, net" on the Consolidated Statements of Income. For further detail, refer to note 21.

2. CHANGE IN ACCOUNTING POLICY

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

Facilitation of the Effects of Reference Rate Reform on Financial Reporting

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

3. FUTURE ACCOUNTING PRONOUNCEMENTS

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

4. 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.

5. SEGMENT INFORMATION

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

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 (expense), net	68	24	13	-	23	17	145
Interest expense, net (2)	185	136	81	19	288	-	709
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.

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, 2021														
Operating revenues from external customers (1)	$	2,718	$	1,501	$	1,276	$	445	$	(175)	$	-	$	5,765
Inter-segment revenues (1)		6		-		4		-		18		(28)		-
Total operating revenues		2,724		1,501		1,280		445		(157)		(28)		5,765
Regulated fuel for generation and purchased power		894		654		-		218		-		(3)		1,763
Regulated cost of natural gas		-		-		472		-		-		-		472
OM&G		536		291		325		140		106		(30)		1,368
Provincial, state and municipal taxes		212		43		69		4		2		-		330
Depreciation and amortization		469		246		121		58		8		-		902
Income from equity investments		-		103		20		4		16		-		143
Other income (expenses), net		59		12		11		15		1		(5)		93
Interest expense, net (2)		138		132		64		21		256		-		611
Income tax expense (recovery)		72		9		62		1		(150)		-		(6)
Non-controlling interest in subsidiaries		-		-		-		1		-		-		1
Preferred stock dividends		-		-		-		-		50		-		50
Net income (loss) attributable to common shareholders	$	462	$	241	$	198	$	21	$	(412)	$	-	$	510
Capital expenditures	$	1,331	$	366	$	515	$	111	$	5	$	-	$	2,328
As at December 31, 2021														
Total assets	$	17,903	$	7,418	$	6,666	$	1,402	$	2,034	$	(1,179)	$	34,244
Investments subject to significant influence	$	-	$	1,215	$	123	$	44	$	-	$	-	$	1,382
Goodwill	$	4,436	$	-	$	1,189	$	68	$	3	$	-	$	5,696

(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 the 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, 2021, 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 **2022**		2021
United States	**$**	**5,346**	$	3,754
Canada		**1,725**		1,566
Barbados		**384**		292
The Bahamas		**122**		110
Dominica		**11**		43
	$	**7,588**	$	5,765

Property Plant and Equipment:

As at millions of dollars		**December 31 2022**		December 31 2021
United States	**$**	**17,382**	$	14,978
Canada		**4,689**		4,440
Barbados		**583**		535
The Bahamas		**342**		322
Dominica		**-**		78
	$	**22,996**	$	20,353

6. REVENUE

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

	Electric			Gas	Other		
millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 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 regulatory deferrals	371	28	12	-	-	-	411
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 Revenue							
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**
For the year ended December 31, 2021							
Regulated Revenue							
Residential	$ 1,449	$ 797	$ 165	$ 642	$ -	$ -	**$** 3,053
Commercial	754	407	232	379	-	-	1,772
Industrial	215	237	26	65	-	(2)	541
Other regulatory deferrals	289	27	7	-	-	-	323
Other (1)	17	33	15	122	-	(8)	179
Finance income (2)(3)	-	-	-	58	-	-	58
Regulated revenue	$ 2,724	$ 1,501	$ 445	$ 1,266	$ -	$ (10)	5,926
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	102	-	102
Other non-regulated operating revenue	-	-	-	14	30	(21)	23
Mark-to-market (3)	-	-	-	-	(289)	3	(286)
Non-regulated revenue	$ -	$ -	$ -	$ 14	$ (157)	$ (18)	(161)
Total operating revenues	$ 2,724	$ 1,501	$ 445	$ 1,280	$ (157)	$ (28)	$ 5,765

(1) Other includes rental revenues, which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

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, 2022, the aggregate amount of the transaction price allocated to remaining performance obligations was $450 million (2021 – $437 million). This amount includes $144 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 2042.

7. REGULATORY ASSETS AND LIABILITIES

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

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

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

As at millions of dollars		**December 31 2022**		December 31 2021
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,166**	$	1,045
Cost recovery clauses		**707**		114
Tampa Electric capital cost recovery for early retired assets		**674**		657
Pension and post-retirement medical plan		**369**		291
FAM		**307**		145
Storm reserve		**103**		-
NMGC winter event gas cost recovery		**69**		117
Storm restoration		**35**		35
Deferrals related to derivative instruments		**30**		23
Environmental remediations		**27**		27
Stranded cost recovery		**27**		26
Other		**106**		86
	$	**3,620**	$	2,566
Current	**$**	**602**	$	253
Long-term		**3,018**		2,313
Total regulatory assets	**$**	**3,620**	$	2,566
Regulatory liabilities				
Accumulated reserve - cost of removal		**895**		819
Deferred income tax regulatory liabilities		**877**		863
Deferrals related to derivative instruments		**230**		241
NMGC gas hedge settlements (note 18)		**162**		-
Cost recovery clauses		**70**		35
Self-insurance fund (note 32)		**30**		28
Storm reserve		**-**		58
Other		**9**		11
	$	**2,273**	$	2,055
Current	**$**	**495**	$	290
Long-term		**1,778**		1,765
Total regulatory liabilities	**$**	**2,273**	$	2,055

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.

Cost Recovery Clauses

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

Tampa Electric Capital Cost Recovery for Early Retired Assets

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

Pension and Post-Retirement Medical Plan

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

FAM

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

Storm Reserve

The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric and PGS systems. As allowed by the FPSC, if the charges to the storm reserve exceed the storm liability, the excess is to be carried as a regulatory asset. Tampa Electric and PGS can petition the FPSC to seek recovery of restoration costs over a 12-month period, or longer, as determined by the FPSC, as well as replenish the reserve. In September 2022, Tampa Electric and PGS were impacted by Hurricane Ian. For further information, refer to "Storm Reserve – Hurricane Ian" in both Tampa Electric and PGS sections below.

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 April 16, 2021, NMGC filed a Motion for Extraordinary Relief, as permitted by the NMPRC rules, to extend the terms of the repayment of the incremental gas costs and to recover a carrying charge. On June 15, 2021, the NMPRC approved the recovery of $108 million USD and related borrowing costs over a period of 30 months beginning July 1, 2021.

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 the recovery of $15 million USD of costs related to Hurricane Dorian in 2019, over a five-year period. The recovery was implemented through rates on January 1, 2021.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge. For further information, refer to "Storm Restoration Costs – Hurricane Matthew" in the GBPC section below.

Deferrals Related to Derivative Instruments

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

Environmental Remediations

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

Stranded Cost Recovery

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

Accumulated Reserve – Cost of Removal ("COR")

This regulatory liability represents the non-ARO COR reserve in Tampa Electric, PGS, NMGC and NSPI. AROs represent the fair value of estimated cash flows associated with the Company's legal obligation to retire its 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 the regulatory deferral of gas options exercised above strike price but will settle in cash in Q1 2023. The value from the cash settlement of this options will flow through to customers via the PGAC.

Regulatory Environments and Updates

Florida Electric Utility

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

Tampa Electric's approved regulated return on equity ("ROE") range for 2022 and 2021 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 (2021 - 10.25 per cent) is used for the calculation of the return on investments for clauses.

Fuel Recovery and Other Cost Recovery Clauses:

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

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

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

Base Rates:

On October 21, 2021, the FPSC approved a settlement agreement filed by Tampa Electric. The settlement agreement allows for an increase to rates 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. It also provides for a 25 basis point increase in the allowed ROE range and mid-point, and $10 million USD of additional revenue, if United States Treasury Bond yields exceed a specific threshold set on the date the FPSC approved the agreement. Under the agreement base rates are frozen from January 1, 2022 to December 31, 2024, unless Tampa Electric's earned ROE were to fall below the bottom of the range during that time. The settlement agreement provides for the deferral of income taxes as a result of changes in tax laws. The changes would be reflected as a regulatory asset or liability and either result in an increase or a decrease in customer rates through a subsequent regulatory process. The settlement agreement further creates a mechanism to recover the costs of retiring coal generation units and meter assets over a period of 15 years which survives the term of that agreement. The settlement agreement sets new depreciation and dismantlement rates effective January 1, 2022 and contains the provisions that Tampa Electric will not have to file another depreciation study during the term of the agreement but will file a new depreciation study no more than one year, nor less than 90 days, before the filing of its next general base rate proceeding. Tampa Electric agreed not to hedge natural gas through the period ending on December 31, 2024.

On August 16, 2022, the FPSC approved Tampa Electric'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.

Storm Reserve – Hurricane Ian:

In September 2022, Tampa Electric was impacted by Hurricane Ian. Total restoration costs were $126 million USD, with $119 million USD of restoration costs charged against Tampa Electric's FPSC approved storm reserve. Total restoration costs charged to the storm reserve have exceeded the reserve balance and have been deferred as a regulatory asset for future recovery. On January 23, 2023, Tampa Electric petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the reserve to the previous approved reserve level of $56 million USD, for a total of approximately $131 million USD. The proposed changes will be decided by the FPSC in March 2023 and recovery is expected to begin in April 2023 through March 2024.

Solar Base Rate Adjustments Included in Base Rates:

During 2017 to 2021, Tampa Electric invested $850 million USD in 600 MW of utility-scale solar photovoltaic projects, which is recoverable through FPSC-approved solar base rate adjustments ("SoBRAs"). AFUDC was earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 600 MW or $104 million 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.

Storm Protection Cost Recovery Clause and Settlement Agreement:

On October 3, 2019, the FPSC issued a rule to implement a Storm Protection Plan ("SPP") Cost Recovery Clause. This clause provides a process for Florida investor-owned utilities, including Tampa Electric, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. 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 Tampa Electric's cost recovery began in January 2021. The current approved plan addressed the years 2020 through 2022, and in April 2022 Tampa Electric submitted a new plan to determine cost recovery in 2023, 2024 and 2025. On October 4, 2022, the FPSC approved Tampa Electric's SPP.

Big Bend Modernization Project:

Tampa Electric 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, Tampa Electric retired the Unit 1 components that will not be used in the modernized plant in 2020 and Big Bend Unit 2 in 2021. Tampa Electric plans to retire Big Bend Unit 3 in 2023 as it is in the best interest of the customers from an economic, environmental risk and operational perspective.

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

Tampa Electric's 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 will be recovered as part of the 2023 subsequent year adjustment. The settlement agreement also includes a new charge to recover the remaining costs of the retiring Big Bend coal generation assets, Units 1 through 3, which will be spread over 15 years and will survive the termination of the settlement agreement. The special capital recovery schedule for all three units was applied beginning January 1, 2022. This recovery mechanism is authorized by and survives the term of the settlement agreement approved by the FPSC in 2021.

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 2022 and 2021 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.

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel 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.

For the period of 2020 through 2022, NSPI operated under a three-year fuel stability plan which resulted in an average annual overall rate increase of 1.5 per cent to recover fuel costs. These rates included recovery of Maritime Link costs.

General Rate Application ("GRA"):

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

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

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

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

Nova Scotia Cap-and-Trade ("Cap-and-Trade") Program:

As at December 31, 2022, the FAM includes a recovery of $172 million (December 31, 2021 – $38 million) non-cash accrual representing the estimated future cost of acquiring emissions credits for the 2019 through 2022 Cap-and-Trade compliance period. Emissions for the compliance period will not be finalized until the completion of the environmental audit which begins in March 2023. Emissions are currently based upon audited actual emissions from 2019 through 2021 and unaudited actuals for 2022. The total cost of compliance with the Cap-and-Trade program compliance period could change depending on the price paid for both credits at remaining provincial auctions and reserve credits purchased from the provincial government, and the results of the 2022 environmental emissions audit.

Lower than forecast Muskrat Falls energy received during the compliance period has resulted in the increased deployment of higher carbon-emitting generation sources. The Province of Nova Scotia has agreed to provide approximately $165 million of relief from the 2019 through 2022 compliance costs, which was equal to the total cost of compliance forecast at the time of the fuel update submitted by NSPI to the UARB in September 2022 as part of the GRA. Discussions related to the final amount of relief and how this relief will be provided are ongoing. Further, NSPI's regulatory framework provides for the recovery of costs prudently incurred to comply with the Cap-and-Trade Program Regulations pursuant to NSPI's FAM.

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. 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 a month, beginning April 2022, contingent on receiving at least 90 per cent of NS Block deliveries, including Supplemental Energy deliveries.

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

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 2022 and 2021 was 8.9 per cent to 11.0 per cent with a 9.9 per cent midpoint, based on an allowed equity capital structure of 54.7 per cent.

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.

Storm Reserve – Hurricane Ian:

In September 2022, Hurricane Ian impacted PGS's operations in Fort Myers and Sarasota. The restoration costs were approximately $2 million USD and $1 million was charged against PGS's FPSC-approved storm reserve.

Base Rates:

On November 19, 2020, the FPSC approved a settlement agreement filed by PGS. The settlement agreement allows for an increase to base rates by $58 million USD annually, effective January 1 2021, which is a $34 million USD increase in revenue and $24 million USD increase of revenues previously recovered through the cast iron and bare steel replacement rider. It provides PGS the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. During 2022, PGS reversed $14 million USD of the $34 million USD accumulated depreciation. No amounts were reversed prior to 2022. In addition, the agreement sets new depreciation rates effective January 1, 2021. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2023, unless its earned ROE were to fall below 8.9 per cent before that time with an allowed equity in the capital structure of 54.7 per cent from investor sources of capital. The settlement agreement provides for the deferral of income taxes as a result of changes in tax laws. The changes would be reflected as a regulatory asset or liability and either result in an increase or a decrease in customer rates through a subsequent regulatory process.

NMGC

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

NMGC's approved ROE for 2022 and 2021 was 9.375 per cent on an allowed equity capital structure of 52 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 the charges based on the next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. In December 2020, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2024.

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.

Weather Normalization Mechanism:

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

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"), an independent regulator, 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 2022 and 2021.

Licenses:

The Government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists to multiple licenses for Generation, Transmission and Distribution, Storage, Dispatch and Sales. In March 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The new licenses are expected to take effect in 2023 on completion of the legislative process. The Dispatch license will have a term of 5 years with the remaining licenses having terms ranging from 25-30 years. BLPC anticipates that any increased costs associated with the implementation of the new multi-licensed structure will be recoverable through BLPC's regulatory framework. BLPC is awaiting final enactment and will work towards implementation of the licenses once received.

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.

On October 4, 2021 BLPC submitted a general rate review application to the FTC. The application seeks a rate adjustment and the implementation of a cost reflective rate structure that will facilitate the changes expected in the newly reformed electricity market and the country's transition towards 100 per cent renewable energy generation. The application seeks recovery of capital investment in plant, equipment and related infrastructure and results in an increase in annual non-fuel revenue of approximately $23 million USD upon approval. The application includes a request for allowed regulatory ROE of 12.50 per cent on an allowed equity capital structure of 65 per cent. On September 16, 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $3 million USD for the remainder of 2022 and approximately $1 million USD per month for 2023. Interim rate relief is effective from September 16, 2022 until the implementation of final rates. The hearing concluded in October 2022. On February 15, 2023, the FTC issued a decision on the BLPC rate review application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities of approximately $70 million USD related to the self-insurance fund, accumulated depreciation, and taxes. The impacts to BLPC's rate base and final rates are not yet determinable. BLPC will seek to clarify aspects of the FTC decision in its compliance filing and is also considering filing a submission to the FTC for a review of the decision. BLPC expects a decision on final rates from the FTC in 2023.

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. A decision is expected from the FTC in 2023.

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 8.23 per cent for 2022 (2021 – 8.37 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 will be adjusted monthly, in-line with actual fuel costs.

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 new rates include a regulatory ROE of 12.84 per cent.

Storm Restoration Costs – Hurricane Matthew:

In 2017, as part of the recovery of costs incurred as a result of Hurricane Matthew, the GBPA approved a fixed per kWh fuel charge and allowed the difference between this and the actual cost of fuel to be applied to the Hurricane Matthew regulatory asset. 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.

8. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

	Carrying Value As at December 31		Equity Income For the year ended December 31		Percentage of Ownership
millions of dollars	**2022**	2021	**2022**	2021	**2022**
LIL (1)	**$ 740**	$ 682	**$ 58**	$ 54	**31.9**
NSPML	**501**	533	**29**	49	**100.0**
M&NP (2)	**128**	123	**21**	20	**12.9**
Lucelec (2)	**49**	44	**4**	4	**19.5**
Bear Swamp (3)	**-**	-	**17**	16	**50.0**
	$ 1,418	$ 1,382	**$ 129**	$ 143	

(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) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method.
(3) The investment balance in Bear Swamp is in a credit position primarily as a result of a $179 million distribution received in 2015. Bear Swamp's credit investment balance of $95 million (2021 – $104 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

Equity investments include a $9 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

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

As at	December 31	
millions of dollars	**2022**	2021
Balance Sheets		
Current assets	**$ 17**	$ 25
PP&E	**1,517**	1,587
Regulatory assets	**265**	247
Non-current assets	**29**	31
Total assets	**$ 1,828**	$ 1,890
Current liabilities	**$ 48**	$ 50
Long-term debt (1)	**1,149**	1,189
Non-current liabilities	**130**	118
Equity	**501**	533
Total liabilities and equity	**$ 1,828**	$ 1,890

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

9. OTHER INCOME, NET

For the millions of dollars	Year ended December 31 **2022**	2021
TECO Guatemala Holdings award (1)	**$ 63**	$ -
AFUDC	**52**	61
Other	**30**	32
	$ 145	$ 93

(1) Refer to note 27 for further detail related to the TECO Guatemala Holdings award.

10. INCOME TAXES

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

millions of dollars	**2022**	2021
Income before provision for income taxes	**$ 1,194**	$ 555
Statutory income tax rate	**29.0%**	29.0%
Income taxes, at statutory income tax rate	**346**	161
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(70)**	(62)
Foreign tax rate variance	**(44)**	(42)
Amortization of deferred income tax regulatory liabilities	**(33)**	(33)
GBPC impairment charge	**21**	-
Tax effect of equity earnings	**(10)**	(16)
Tax credits	**(18)**	(13)
Other	**(7)**	(1)
Income tax expense (recovery)	**$ 185**	$ (6)
Effective income tax rate	**15%**	(1%)

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. During 2022, the Company recorded a $9 million regulatory liability 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	**2022**	2021
Current income taxes		
Canada	**$ 25**	$ 20
United States	**8**	11
Deferred income taxes		
Canada	**120**	(33)
United States	**252**	118
Other	**-**	2
Investment tax credits		
United States	**(7)**	(11)
Operating loss carryforwards		
Canada	**(92)**	(64)
United States	**(121)**	(49)
Income tax expense (recovery)	**$ 185**	$ (6)

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		**2022**		2021
Canada	**$**	**173**	$	244
United States		**1,063**		289
Other		**(42)**		22
Income before provision for income taxes	**$**	**1,194**	$	555

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

millions of dollars		**2022**		2021
Deferred income tax assets:				
Tax loss carryforwards	**$**	**1,207**	$	873
Tax credit carryforwards		**415**		375
Regulatory liabilities - cost of removal		**177**		170
Derivative instruments		**45**		188
Other		**428**		434
Total deferred income tax assets before valuation allowance		**2,272**		2,040
Valuation allowance		**(312)**		(256)
Total deferred income tax assets after valuation allowance	**$**	**1,960**	$	1,784
Deferred income tax (liabilities):				
PP&E	**$**	**(2,981)**	$	(2,622)
Regulatory assets		**(219)**		(78)
Derivative instruments		**(125)**		(197)
Other		**(594)**		(460)
Total deferred income tax liabilities	**$**	**(3,919)**	$	(3,357)
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets	**$**	**237**	$	295
Long-term deferred income tax liabilities		**(2,196)**		(1,868)
Net deferred income tax liabilities	**$**	**(1,959)**	$	(1,573)

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 $312 million has been recorded as at December 31, 2022 (2021 – $256 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, 2022, $3.8 billion (2021 – $2.9 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, 2022 consisted of the following:

millions of dollars	Tax Carryforwards	Subject to Valuation Allowance	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 2,372	$ (977)	$ 1,395	2026 - 2042
Capital loss	79	(79)	-	Indefinite
United States				
Federal NOL	$ 2,082	$ -	$ 2,082	2032 - Indefinite
State NOL	1,489	-	1,489	2032 - Indefinite
Tax credit	415	-	415	2025 - 2042
Other				
NOL	$ 73	$ (33)	$ 40	2023 - 2029

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

millions of dollars	**2022**	2021
Balance, January 1	**$ 28**	$ 30
Increases due to tax positions related to current year	**5**	4
Increases due to tax positions related to a prior year	**2**	1
Decreases due to tax positions related to a prior year	**(2)**	(1)
Decreases due to settlement with tax authorities	**-**	(6)
Balance, December 31	**$ 33**	$ 28

The total amount of unrecognized tax benefits as at December 31, 2022 was $33 million (2021 - $28 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $7 million (2021 – $6 million) with $1 million interest expense recognized in the Consolidated Statements of Income (2021 – nil). 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 (2021 – $62 million), including interest. NSPI has prepaid $55 million (2021 – $23 million) of the amount in dispute, as required by CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute 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, 2022, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

11. COMMON STOCK

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

Issued and outstanding:	2022 millions of shares		2022 millions of dollars	2021 millions of shares		2021 millions of dollars
Balance, December 31, 2021	**261.07**	**$**	**7,242**	251.43	$	6,705
Issuance of common stock under ATM program (1)(2)	**4.07**		**248**	4.99		284
Issued under the DRIP, net of discounts	**4.21**		**238**	3.90		215
Senior management stock options exercised and Employee Share Purchase Plan	**0.60**		**34**	0.75		38
Balance, December 31, 2022	**269.95**	**$**	**7,762**	261.07	$	7,242

(1) As at December 31, 2021, a total of 4,987,123 common shares were issued under Emera's ATM program at an average price of $57.63 per share for gross proceeds of $287 million ($284 million net of after-tax issuance costs).
(2) For the year ended December 31, 2022, 4,072,469 common shares were issued under Emera's ATM program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs).

On August 12, 2021, Emera renewed its ATM Program that allows the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was renewed pursuant to a prospectus supplement to the Company's short form base shelf prospectus dated August 5, 2021. The ATM program is expected to remain in effect until September 5, 2023. As at December 31, 2022, an aggregate gross sales limit of $207 million remains available for issuance under the ATM program.

As at December 31, 2022, the following common shares were reserved for issuance: 6 million (2021 – 6.2 million) under the senior management stock option plan, 2.7 million (2021 – 3.1 million) under the employee common share purchase plan and 10 million (2021 – 14.2 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, 2022, Emera is in compliance with this requirement.

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 **2022**	 2021
Numerator		
Net income attributable to common shareholders	**$ 945.1**	$ 510.5
Diluted numerator	**945.1**	510.5
Denominator		
Weighted average shares of common stock outstanding	**265.5**	255.9
Weighted average deferred share units outstanding (1)	**-**	1.3
Weighted average shares of common stock outstanding – basic	**265.5**	257.2
Stock-based compensation	**0.4**	0.4
Weighted average shares of common stock outstanding – diluted	**265.9**	257.6
Earnings per common share		
Basic	**$ 3.56**	$ 1.98
Diluted	**$ 3.55**	$ 1.98

(1) Effective February 10, 2022, deferred share units are no longer able to be settled in shares and are therefore no longer included in the calculation of earnings per common share.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of AOCI are as follows:

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

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

For the			Year ended December 31	
millions of dollars			**2022**	2021
	Affected line item in the Consolidated Financial Statements			
Gains on derivatives recognized as cash flow hedges				
Interest rate hedge	Interest expense, net	**$**	**(2)** $	(1)
Net change in unrecognized pension and post-retirement benefit costs				
Actuarial losses	Other income, net	**$**	**10** $	24
Amounts reclassified into obligations	Pension and post-retirement benefits		**15**	102
Total before tax			**25**	126
Income tax expense			**(1)**	(2)
Total net of tax		**$**	**24** $	124
Total reclassifications out of AOCI, net of tax, for the period		**$**	**22** $	123

14. INVENTORY

As at	**December 31**	December 31
millions of dollars	**2022**	2021
Fuel	**$ 404**	$ 255
Materials	**365**	283
Total	**$ 769**	$ 538

15. DERIVATIVE INSTRUMENTS

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

	Derivative Assets		**Derivative Liabilities**	
As at	**December 31**	December 31	**December 31**	December 31
millions of dollars	**2022**	2021	**2022**	2021
Regulatory deferral:				
Commodity swaps and forwards	**$ 186**	$ 146	**$ 42**	$ 16
FX forwards	**18**	7	**1**	8
Physical natural gas purchases and sales	**52**	88	**-**	-
	256	241	**43**	24
HFT derivatives:				
Power swaps and physical contracts	**89**	33	**77**	32
Natural gas swaps, futures, forwards, physical contracts	**340**	208	**1,224**	818
	429	241	**1,301**	850
Other derivatives:				
Equity derivatives	**-**	11	**5**	-
FX forwards	**5**	-	**23**	-
	5	11	**28**	-
Total gross current derivatives	**690**	493	**1,372**	874
Impact of master netting agreements:				
Regulatory deferral	**(18)**	(4)	**(18)**	(4)
HFT derivatives	**(276)**	(188)	**(276)**	(188)
Total impact of master netting agreements	**(294)**	(192)	**(294)**	(192)
Total derivatives	**$ 396**	$ 301	**$ 1,078**	$ 682
Current (1)	**296**	195	**888**	533
Long-term (1)	**100**	106	**190**	149
Total derivatives	**$ 396**	$ 301	**$ 1,078**	$ 682

(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, the 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. As of December 31, 2022, the unrealized gain in AOCI was $16 million, net of tax (2021 – $18 million, net of tax). For the year ended December 31, 2022, unrealized gains of $2 million (2021 – $1 million) have been reclassified from AOCI into interest expense. The Company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next twelve months.

Regulatory Deferral

The Company has recorded the following changes in realized and unrealized gains (losses) 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			**2022**			2021
Unrealized gain (loss) in regulatory assets	**$ -**	**$ (69)**	**$ 1**	$ -	$ (7)	$ 9
Unrealized gain (loss) in regulatory liabilities	**28**	**343**	**16**	88	218	(3)
Realized loss in regulatory assets	**-**	**48**	**-**	-	-	-
Realized gain in regulatory liabilities	**-**	**(41)**	**-**	-	(3)	-
Realized (gain) loss in inventory (1)	**-**	**(121)**	**1**	-	(8)	5
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(64)**	**(146)**	**-**	-	(39)	5
Total change in derivative instruments	**$ (36)**	**$ 14**	**$ 18**	$ 88	$ 161	$ 16

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

As at December 31, 2022, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2023	2024-2026
Physical natural gas purchases:		
Natural gas (Mmbtu)	6	-
Commodity swaps and forwards purchases:		
Natural gas (Mmbtu)	18	12
Power (MWh)	1	1
FX swaps and forwards:		
FX contracts (millions of USD)	$ 206	$ 123
Weighted average rate	1.2832	1.3064
% of USD requirements	50%	28%

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 **2022**	2021
Power swaps and physical contracts in non-regulated operating revenues	**$ 17**	$ 4
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**47**	(142)
Total gains (losses) in net income	**$ 64**	$ (138)

As at December 31, 2022, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2023	2024	2025	2026	2027 and thereafter
Natural gas purchases (Mmbtu)	319	92	42	36	131
Natural gas sales (Mmbtu)	492	205	105	6	19
Power purchases (MWh)	2	-	-	-	-
Power sales (MWh)	2	-	-	-	-

Other Derivatives

As at December 31, 2022, 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 2.8 million shares and extends until December 2023. The FX forwards have a combined notional amount of $448 million USD and expire throughout 2023, 2024, and 2025.

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

For the millions of dollars				Year ended December 31
		2022		2021
	FX Forwards	**Equity Derivatives**	FX Forwards	Equity Derivatives
Unrealized gain (loss) in OM&G	**$ -**	**$ (5)**	$ -	$ 11
Unrealized loss in other income, net	**(18)**	**-**	(15)	-
Realized gain (loss) in OM&G	**-**	**(17)**	-	15
Realized gain (loss) in other income, net	**(6)**	**-**	18	-
Total gains (losses) in net income	**$ (24)**	**$ (22)**	$ 3	$ **26**

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, 2022, the maximum exposure the Company had to credit risk was $1.9 billion (2021 – $1.3 billion), which includes accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, 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, 2022 was $386 million (2021 – $341 million), which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements, 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, 2022, the Company had $131 million (2021 – $114 million) in financial assets, considered to be past due, which have been outstanding for an average 60 days. The fair value of these financial assets is $114 million (2021 – $93 million), the difference of which is included in the allowance for credit losses. These assets primarily relate to accounts receivable from electric and gas revenue.

Concentration Risk

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

As at	**December 31, 2022**		December 31, 2021	
	millions of dollars	**% of total exposure**	millions of dollars	% of total exposure
Receivables, net				
Regulated utilities:				
Residential	**$ 455**	**19%**	$ 384	24%
Commercial	**192**	**8%**	167	10%
Industrial	**121**	**5%**	54	3%
Other	**122**	**5%**	91	6%
	890	**37%**	696	43%
Trading group:				
Credit rating of A- or above	**125**	**5%**	66	4%
Credit rating of BBB- to BBB+	**75**	**3%**	107	7%
Not rated	**307**	**13%**	132	8%
	507	**21%**	305	19%
Other accounts receivable	**585**	**25%**	329	20%
	1,982	**83%**	1,330	82%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**202**	**9%**	155	9%
Credit rating of BBB- to BBB+	**8**	**0%**	22	1%
Not rated	**186**	**8%**	124	8%
	396	**17%**	301	18%
	$ 2,378	**100%**	$ 1,631	100%

Cash Collateral

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

As at millions of dollars		**December 31 2022**		December 31 2021
Cash collateral provided to others	**$**	**224**	$	212
Cash collateral received from others	**$**	**112**	$	100

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, 2022, the total fair value of derivatives in a liability position was $1,078 million (December 31, 2021 – $682 million). If the credit ratings of the Company were reduced below investment grade, the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

As at 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	-	-	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
	5	23	-	28
Total liabilities	73	179	826	1,078
Net assets (liabilities)	$ 59	$ (5)	$ (736)	$ (682)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2021 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 101	$ 41	$ -	$ 142
FX forwards	-	7	-	7
Physical natural gas purchases and sales	-	-	88	88
	101	48	88	237
HFT derivatives:				
Power swaps and physical contracts	4	5	4	13
Natural gas swaps, futures, forwards, physical contracts and related transportation	(1)	29	12	40
	3	34	16	53
Other derivatives:				
Equity derivatives	11	-	-	11
Total assets	115	82	104	301
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	7	5	-	12
FX forwards	-	8	-	8
	7	13	-	20
HFT derivatives:				
Power swaps and physical contracts	4	5	3	12
Natural gas swaps, futures, forwards and physical contracts	13	122	515	650
	17	127	518	662
Total liabilities	24	140	518	682
Net assets (liabilities)	$ 91	$ (58)	$ (414)	$ (381)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2022 was as follows:

	Regulatory Deferral	***HFT Derivatives***		
millions of dollars	**Physical natural gas purchases**	**Power**	**Natural gas**	**Total**
Balance, January 1, 2022	**$ 88**	**$ 4**	**$ 12**	**$ 104**
Realized gains included in fuel for generation and purchased power	**(64)**	**-**	**-**	**(64)**
Unrealized gains included in regulatory liabilities	**28**	**-**	**-**	**28**
Total realized and unrealized gains included in non-regulated operating revenues	**-**	**-**	**22**	**22**
Balance, December 31, 2022	**$ 52**	**$ 4**	**$ 34**	**$ 90**

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2022 was as follows:

	HFT Derivatives		
millions of dollars	**Power**	**Natural gas**	**Total**
Balance, January 1, 2022	**$ 3**	**$ 515**	**$ 518**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**(2)**	**310**	**308**
Balance, December 31, 2022	**$ 1**	**$ 825**	**$ 826**

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives include third-party sourced pricing for instruments based on illiquid markets. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value 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 fair value of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at millions of dollars	Fair Value		Significant Unobservable Input	Low	High	December 31, 2022 Weighted average (1)
	Assets	**Liabilities**				
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 fair value of the instruments.

As at millions of dollars	Fair Value		Significant Unobservable Input	Low	High	December 31, 2021 Weighted average (1)
	Assets	**Liabilities**				
Regulatory deferral – Physical natural gas purchases	**$** 88	$ -	Third-party pricing	$4.51	$26.09	$9.74
HFT derivatives – Power swaps and physical contracts	4	3	Third-party pricing	$37.05	$213.00	$99.34
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	12	515	Third-party pricing	$1.90	$21.53	$8.80
Total	**$** 104	$ 518				
Net liability		$ 414				

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

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

As at millions of dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
December 31, 2022	**$ 16,318**	**$ 14,670**	**$ -**	**$ 14,284**	**$ 386**	**$ 14,670**
December 31, 2021	$ 14,658	$ 16,775	$ -	$ 16,308	$ 467	$ 16,775

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, 2022, the fair value of the Hybrid Notes was $1.1 billion (2021 – $1.7 billion). An after-tax foreign currency loss of $97 million was recorded in AOCI for the year ended December 31, 2022 (2021 – $5 million after-tax gain).

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 $157 million for the year ended December 31, 2022 (2021 – $149 million). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments.

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

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

18. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars	**December 31 2022**	December 31 2021
Customer accounts receivable – billed	**$ 1,096**	$ 767
Customer accounts receivable – unbilled	**424**	318
Allowance for credit losses	**(17)**	(21)
Capitalized transportation capacity (1)	**781**	316
NMGC gas hedge settlement receivable (2)	**162**	-
Income tax receivable	**9**	8
Prepaid expenses	**82**	65
Other	**360**	280
Total receivables and other current assets	**$ 2,897**	$ 1,733

(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) Related amount is included in regulatory liabilities for NMGC as gas hedges are part of the PGAC. Refer to note 7.

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 63 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 that they will be exercised.

As at millions of dollars	Classification	**December 31 2022**	December 31 2021
Right-of-use asset	Other long-term assets	**$ 58**	$ 58
Lease liabilities			
Current	Other current liabilities	**3**	3
Long-term	Other long-term liabilities	**59**	58
Total lease liabilities		**$ 62**	$ 61

The Company has recorded lease expense of $138 million for the year ended December 31, 2022 (2021 – $150 million), of which $131 million (2021 – $142 million) relates to variable costs for power generation facility finance leases, recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

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

millions of dollars	2023	2024	2025	2026	2027	Thereafter	Total
Minimum lease payments	$ 6	$ 6	$ 5	$ 3	$ 3	$ 116	$ 139
Less imputed interest							(77)
Total							$ 62

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

For the	Year ended December 31 **2022**	2021
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of dollars)	**$ 8**	$ 7
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of dollars)	**$ 1**	$ -
Weighted average remaining lease term (years)	**44**	44
Weighted average discount rate- operating leases	**3.98%**	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 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 January 2022, the Company leased a 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 new 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 2022**		December 31 2021
Total minimum lease payment to be received	**$**	**1,393**	$	947
Less: amounts representing estimated executory costs		**(205)**		(165)
Minimum lease payments receivable	**$**	**1,188**	$	782
Estimated residual value of leased property (unguaranteed)		**183**		183
Less: unearned finance lease income		**(733)**		(443)
Net investment in direct finance and sales-type leases	**$**	**638**	$	522
Principal due within one year (included in "Receivables and other current assets")		**34**		19
Net Investment in direct finance and sales type leases - long-term	**$**	**604**	$	503

As at December 31, 2022, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

millions of dollars		2023		2024		2025		2026		2027		Thereafter		Total
Minimum lease payments to be received	$	90	$	92	$	95	$	94	$	92	$	930	$	1,393
Less: executory costs														(205)
Total													$	1,188

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 2022**		December 31 2021
Generation	2 to 131	**$**	**13,083**	$	11,173
Transmission	10 to 80		**2,731**		2,532
Distribution	10 to 65		**6,978**		6,305
Gas transmission and distribution	13 to 83		**5,061**		4,385
General plant and other (1)	2 to 71		**2,723**		2,473
Total cost			**30,576**		26,868
Less: Accumulated depreciation (1)			**(9,574)**		(8,739)
			21,002		18,129
Construction work in progress (1)			**1,994**		2,224
Net book value		**$**	**22,996**	$	20,353

(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, 2022, SeaCoast's share of plant in service was $27 million USD (2021 - $27 million USD), and accumulated depreciation of $1 million USD (2021 - $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 and defined-contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, New Mexico, Barbados, 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
	2022		2021	
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	**$ 2,624**	**$ 318**	$ 2,759	$ 339
Service cost	**41**	**4**	43	5
Plan participant contributions	**6**	**6**	6	4
Interest cost	**80**	**9**	67	8
Benefits paid	**(174)**	**(31)**	(160)	(27)
Actuarial gains	**(480)**	**(79)**	(89)	(10)
Settlements and curtailments	**(6)**	**-**	-	-
Foreign currency translation adjustment	**67**	**16**	(2)	(1)
Balance, December 31	**$ 2,158**	**$ 243**	$ 2,624	$ 318
Change in plan assets				
Balance, January 1	**$ 2,702**	**$ 51**	$ 2,605	$ 52
Employer contributions	**45**	**24**	42	21
Plan participant contributions	**6**	**6**	6	4
Benefits paid	**(174)**	**(31)**	(160)	(27)
Actual return on assets, net of expenses	**(489)**	**(7)**	214	2
Settlements and curtailments	**(6)**	**-**	-	-
Foreign currency translation adjustment	**79**	**3**	(5)	(1)
Balance, December 31	**$ 2,163**	**$ 46**	$ 2,702	$ 51
Funded status, end of year	**$ 5**	**$ (197)**	$ 78	$ (267)

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

Plans with PBO/APBO in Excess of Plan Assets
The aggregate financial position for all pension plans where the PBO or APBO (for post-retirement benefit plans) exceeds the plan assets for the years ended December 31 is as follows:

millions of dollars	**2022**		2021	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 1,006**	**$ 221**	$ 140	$ 290
Fair value of plan assets	**914**	**-**	35	-
Funded status	**$ (92)**	**$ (221)**	$ (105)	$ (290)

Plans with Accumulated Benefit Obligation ("ABO") in Excess of Plan Assets

The ABO for the defined benefit pension plans was $2,080 million as at December 31, 2022 (2021 – $2,507 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 is as follows:

millions of dollars	**2022**	2021
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 111**	$ 133
Fair value of plan assets	**33**	35
Funded status	**$ (78)**	$ (98)

Balance Sheet

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

As at millions of dollars		**December 31 2022**		December 31 2021
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	**$ (13)**	**$ (20)**	$ (7)	$ (20)
Long-term liabilities	**(80)**	**(201)**	(100)	(270)
Other long-term assets	**98**	**24**	185	23
AOCI, net of tax and regulatory assets	**358**	**22**	230	90
Less: Deferred income tax (expense) recovery in AOCI	**(7)**	**(1)**	(8)	1
Net amount recognized	**$ 356**	**$ (176)**	$ 300	$ (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
Defined Benefit Pension Plans		
Balance, January 1, 2022	$ 192	$ 30
Amortized in current period	(21)	(10)
Current year addition to AOCI or regulatory assets	147	(5)
Change in FX rate	18	-
Balance, December 31, 2022	$ 336	$ 15
Non-pension benefits plans		
Balance, January 1, 2022	$ 91	$ -
Amortized in current period	(2)	-
Current year addition to AOCI or regulatory assets	(62)	(10)
Change in FX rate	4	-
Balance, December 31, 2022	$ 31	$ (10)

As at millions of dollars		**December 2022**		December 2021
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	**$ 15**	**$ (10)**	$ 30	$ -
Deferred income tax expense (recovery)	**7**	**1**	8	(1)
AOCI, net of tax	**22**	**(9)**	**38**	**(1)**
Regulatory assets	**336**	**31**	192	91
AOCI, net of tax and regulatory assets	**$ 358**	**$ 22**	$ **230**	$ **90**

Benefit Cost Components

Emera's net periodic benefit cost included the following:

As at millions of dollars				Year ended December 31
		2022		2021
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 41**	**$ 4**	$ 43	$ 5
Interest cost	**80**	**9**	67	8
Expected return on plan assets	**(144)**	**-**	(132)	(1)
Current year amortization of:				
Actuarial losses	**8**	**-**	21	3
Regulatory assets (liability)	**21**	**2**	24	2
Settlement, curtailments	**2**	**-**	-	-
Total	**$ 8**	**$ 15**	$ 23	$ 17

The expected return on plan assets is determined based on the market-related value of plan assets of $2,482 million as at January 1, 2022 (2021 – $2,151 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

Pension Plan Asset Allocations

Emera's investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan's actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Within each asset class, a further diversification is undertaken through the investment in a broad range of investment and non-investment grade securities. Emera's target asset allocation is as follows:

Canadian Pension Plans

Asset Class	Target Range at Market		
Short-term securities	0%	to	5%
Fixed income	35%	to	50%
Equities:			
Canadian	7%	to	17%
Non-Canadian	36%	to	60%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average		
Fixed income	30%	to	50%
Equities	50%	to	70%

Pension Plan assets are overseen by the respective Management Pension Committees in the sponsoring companies. All pension investments are in accordance with policies approved by the respective Board of Directors of each sponsoring company.

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

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
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%**

As at					December 31, 2021
Cash and cash equivalents	$ -	$ 60	$ -	$ 60	2%
Net in-transits	-	(84)	-	(84)	(3)%
Equity securities:					
Canadian equity	-	97	-	97	4 %
United States equity	-	366	-	366	14 %
Other equity	-	215	-	215	8 %
Fixed income securities:					
Government	-	-	132	132	5 %
Corporate	-	-	117	117	4 %
Other	-	8	3	11	- %
Mutual funds	-	86	-	86	3 %
Other	-	1	(1)	-	- %
Open-ended investments measured at NAV (1)	952	-	-	952	35 %
Common collective trusts measured at NAV (2)	750	-	-	750	28%
Total	$ 1,702	$ 749	$ 251	$ 2,702	100%

(1) 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 honor subscription and redemption activity regularly.
(2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The funds honor subscription and redemption activity regularly.

Refer to note 16 for more information on the fair value hierarchy and inputs used to measure fair value.

Post-Retirement Benefit Plans
There are no assets set aside to pay for most of the Company's post-retirement benefit plans. As is common practice, post-retirement health benefits are paid from general accounts as required. The primary exceptions to this is the NMGC Retiree Medical Plan, which is fully funded.

Investments in Emera
As at December 31, 2022 and 2021, the 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 the 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		
2023	$ 44	$ 20
Expected benefit payments		
2023	164	22
2024	161	23
2025	168	23
2026	172	22
2027	178	22
2028 – 2032	919	105

Assumptions
The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

		2022		2021
(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	**5.33 %**	**5.31 %**	3.05 %	2.81 %
Discount rate - future service	**5.34 %**	**5.32 %**	3.18 %	2.92 %
Rate of compensation increase	**3.62 %**	**3.61 %**	3.31 %	3.29 %
Health care trend - initial (next year)	**-**	**5.40 %**	-	5.09 %
- ultimate	**-**	**3.77 %**	-	3.77 %
- year ultimate reached		**2043**		2042
Benefit cost for year ended December 31:				
Discount rate - past service	**3.05 %**	**2.81 %**	2.49 %	2.48 %
Discount rate - future service	**3.18 %**	**2.92 %**	2.64 %	2.51 %
Expected long-term return on plan assets	**6.07 %**	**1.32 %**	5.86 %	- %
Rate of compensation increase	**3.31 %**	**3.29 %**	2.89 %	3.04 %
Health care trend - initial (current year)	**-**	**5.09 %**	-	5.64 %
- ultimate	**-**	**3.77 %**	-	4.35 %
- year ultimate reached		**2042**		2038

Actual assumptions used differ by plan.

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated cash flows from the pension plan.

Defined Contribution Plan
Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2022 was $41 million (2021 – $45 million).

22. GOODWILL

The change in goodwill for the year ended December 31 is due to the following:

millions of dollars		**2022**		2021
Balance, January 1	**$**	**5,696**	$	5,720
GBPC impairment charge (1)		**(73)**		-
Change in FX rate		**389**		(24)
Balance, December 31	**$**	**6,012**	$	5,696

(1) At the beginning of the period, Emera's accumulated impairment charges related to GBPC were $30 million.

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, 2022, primarily relates to TECO Energy. Emera's reporting units with goodwill are Tampa Electric, PGS, NMGC, and GBPC.

In 2022, Emera performed a qualitative impairment assessment for Tampa Electric and PGS, concluding that the fair value of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessments were performed and no impairment charges were recognized. For the NMGC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment using a combination of the income approach and market approach. This assessment estimated that the fair value of the NMGC reporting unit exceeded its carrying amount, including goodwill. As a result of this assessment, no impairment charges were recognized.

In 2022, the Company elected to bypass a qualitative assessment and performed a quantitative impairment assessment for GBPC, using the income approach, as this reporting unit is sensitive to changes in assumptions due to limited excess of fair value over carrying amount, including goodwill. Although the cash flows of GBPC have not changed significantly compared to previous periods, it was determined that the fair value did not exceed its carrying amount, including goodwill, primarily due to an increase in discount rates. The discount rate for the reporting unit was negatively impacted by changes in the macro-economic environment, including the risk-free rate assumption. As a result of this assessment, a goodwill impairment charge of $73 million was recorded in 2022, reducing the GBPC goodwill balance to nil as at December 31, 2022. This non-cash charge is included in "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		**2022**	**Weighted average interest rate**		2021	Weighted average interest rate
Tampa Electric Company ("TEC")						
Advances on term, revolving and accounts receivable facilities	**$**	**1,380**	**5.00 %**	$	945	0.58 %
Emera						
Non-revolving term facilities		**796**	**5.19 %**		400	0.96 %
Bank indebtedness		**-**	**- %**		6	- %
TECO Finance						
Advances on revolving credit and term facilities		**481**	**5.47 %**		355	1.20 %
NMGC						
Advances on revolving credit facilities		**59**	**5.15 %**		25	1.20 %
GBPC						
Advances on revolving credit facilities		**10**	**5.25 %**		10	5.25 %
NSPI						
Bank indebtedness		**-**	**- %**		1	- %
Short-term debt	**$**	**2,726**		$	1,742	

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		2022	2021
TEC - Unsecured committed revolving credit facility	2026	**$**	**1,084**	$ 1,014
TECO Energy/TECO Finance - revolving credit facility	2026		**542**	507
Emera - non-revolving term facility	2023		**400**	400
Emera - non-revolving term facility	2023		**400**	-
TEC - Unsecured non-revolving facility	2023		**542**	634
NMGC - revolving credit facility	2026		**169**	158
GBPC - revolving credit facility	on demand		**18**	16
Total		**$**	**3,155**	$ 2,729
Less:				
Advances under revolving credit and term facilities			**2,731**	1,735
Letters of credit issued within the credit facilities			**4**	4
Total advances under available facilities			**2,735**	1,739
Available capacity under existing agreements		**$**	**420**	$ 990

The weighted average interest rate on outstanding short-term debt at December 31, 2022 was 5.01 per cent (2021 – 0.83 per cent).

Recent Significant Financing Activity by Segment

Florida Electric Utilities

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

Other

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

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

24. OTHER CURRENT LIABILITIES

As at millions of dollars		December 31 2022		December 31 2021
Accrued charges	**$**	**174**	$	157
Nova Scotia Cap-and-Trade Program provision (note 7)		**172**		-
Accrued interest on long-term debt		**97**		75
Pension and post-retirement liabilities (note 21)		**33**		27
Sales and other taxes payable		**14**		6
Income tax payable		**9**		6
Other		**80**		95
	$	**579**	$	366

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) 2022	2021	Maturity		2022		2021
Emera							
Bankers acceptances, LIBOR loans	Variable	Variable	2027	**$**	**403**	$	378
Unsecured fixed rate notes	2.90%	2.90%	2023		**500**		500
Fixed to floating subordinated notes (USD) (2)	6.75%	6.75%	2076		**1,625**		1,521
				$	**2,528**	$	2,399
Emera Finance							
Unsecured senior notes (USD)	3.65%	3.65%	2024 - 2046	**$**	**3,725**	$	3,487
Tampa Electric (3)							
Fixed rate notes and bonds (USD)	4.15%	4.15%	2024 - 2052	**$**	**4,341**	$	3,683
PGS							
Fixed rate notes and bonds (USD)	3.78%	3.78%	2024 - 2052	**$**	**772**	$	660
NMGC							
Fixed rate notes and bonds (USD)	3.11%	3.11%	2026 - 2051	**$**	**521**	$	488
Non-revolving term facility, floating rate	Variable	Variable	2024		**108**		101
				$	**629**	$	589
NMGI							
Fixed rate notes and bonds (USD)	3.64%	3.64%	2024	**$**	**203**	$	190
NSPI							
Discount notes	Variable	Variable	2024 - 2027	**$**	**881**	$	376
Medium term fixed rate notes	5.14%	5.14%	2025 - 2097		**2,665**		2,665
				$	**3,546**	$	3,041
EBP							
Senior secured credit facility	Variable	Variable	2026	**$**	**249**	$	249
ECI							
Secured senior notes (USD)	Variable	Variable	2026	**$**	**86**	$	84
Amortizing fixed rate notes (USD)	3.97%	3.97%	2024 - 2026		**100**	$	104
Non-revolving term facility, floating rate	Variable	Variable	2027		**30**	$	28
Non-revolving term facility, fixed rate	2.05%	2.36%	2025 - 2026		**91**	$	101
Secured fixed rate senior notes (4)	3.06%	4.43%	2023 - 2029		**142**	$	161
				$	**449**	$	478
Adjustments							
Fair market value adjustment - TECO Energy acquisition (5)				**$**	**2**	$	3
Debt issuance costs					**(126)**		(121)
Amount due within one year					**(574)**		(462)
				$	**(698)**	$	(580)
Long-Term Debt				**$**	**15,744**	$	14,196

(1) Weighted average interest rate of fixed rate long-term debt.
(2) In 2022, the Company recognized $110 million in interest expense (2021 – $102 million) related to its fixed to floating subordinated notes.
(3) A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.
(4) Notes are issued and payable in either USD or BBD.
(5) On acquisition of TECO Energy, Emera recorded a fair market value adjustment on the unregulated long-term debt acquired. The fair market value adjustment is amortized over the remaining term of the debt.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of dollars	Maturity		2022		2021
Emera – revolving credit facility (1)	June 2027	**$**	**900**	$	900
NSPI - revolving credit facility (1)	December 2027		**800**		600
NSPI - non-revolving credit facility	July 2024		**400**		-
NMGC - non-revolving credit facility	March 2024		**108**		-
ECI – revolving credit facilities	2023-2032		**11**		27
Total		**$**	**2,219**	$	1,527
Less:					
Borrowings under credit facilities			**1,396**		770
Letters of credit issued inside credit facilities			**12**		124
Use of available facilities		**$**	**1,408**	$	894
Available capacity under existing agreements		**$**	**811**	$	633

(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, 2022
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.57 : 1

Recent Significant Financing Activity by Segment

Florida Electric Utilities

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

On July 12, 2022, TEC completed an issuance of $600 million USD senior notes. The issuance included $300 million USD senior notes that bear an interest rate of 3.875 per cent with a maturity date of July 12, 2024, and $300 million USD senior notes that bear an interest rate of 5 per cent with a maturity date of July 15, 2052.

Canadian Electric Utilities

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

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

Gas Utilities and Infrastructure

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

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

Other Electric Utilities

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

Other

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

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	2023	2024	2025	2026	2027	Thereafter	Total
Emera	$ 500	$ -	$ -	$ 1,625	$ 403	$ -	$ 2,528
Emera US Finance LP	-	407	-	1,016	-	2,302	3,725
Tampa Electric	-	356	-	-	-	3,985	4,341
PGS	-	51	-	-	-	721	772
NMGC	-	108	-	95	-	426	629
NMGI	-	203	-	-	-	-	203
NSPI	-	398	125	40	483	2,500	3,546
EBP	-	-	-	249	-	-	249
ECI	74	90	137	85	60	3	449
Total	$ 574	$ 1,613	$ 262	$ 3,110	$ 946	$ 9,937	$ 16,442

26. ASSET RETIREMENT OBLIGATIONS

AROs mostly relate to reclamation of land at the thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment and a pipeline site. Certain hydro, transmission and distribution assets may have additional AROs that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of dollars	**2022**	2021
Balance, January 1	**$ 174**	$ 178
Accretion included in depreciation expense	**9**	10
Change in FX rate	**3**	(1)
Additions	**1**	1
Accretion deferred to regulatory asset (included in PP&E)	**1**	(2)
Liabilities settled (1)	**(1)**	(13)
Revisions in estimated cash flows	**(13)**	-
Other	**-**	1
Balance, December 31	**$ 174**	$ 174

(1) Tampa Electric produced ash and other by-products, collectively known as CCR's, at its Big Bend and Polk power stations. The decrease in ARO in 2021 was due to the closure of CCR management facilities.

27. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2022, 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	2023	2024	2025	2026	2027	Thereafter	Total
Transportation (1)	$ 693	$ 516	$ 423	$ 383	$ 367	$ 2,817	$ 5,199
Purchased power (2)	269	243	237	228	243	2,145	3,365
Fuel, gas supply and storage	1,161	282	138	40	5	1	1,627
Capital projects	264	89	4	1	-	-	358
Equity investment commitments (3)	240	-	-	-	-	-	240
Other	149	142	132	49	42	189	703
	$ 2,776	$ 1,272	$ 934	$ 701	$ 657	$ 5,152	$ 11,492

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $144 million related to a gas transportation contract between PGS and SeaCoast through 2040.

(2) Annual requirement to purchase electricity production from IPPs or other utilities over varying contract lengths.

(3) Emera has a commitment to make a final equity contribution to the LIL upon its commissioning. Once commissioned, the commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation to the Maritime Link and LIL.

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

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

B. Legal Proceedings

TECO Guatemala Holdings ("TGH")

Prior to Emera's acquisition of TECO Energy in 2016, TGH, a wholly owned subsidiary of TECO Energy, divested of its indirect investment in the Guatemala electricity sector, but retained certain claims against the Republic of Guatemala ("Guatemala"). In 2013, TGH asserted an arbitration claim against Guatemala with the International Centre for the Settlement of Investment Disputes ("ICSID") under the Dominican Republic Central America – United States Free Trade Agreement. The arbitration concerned TGH's allegation that Guatemala unfairly set the distribution tariff for a local distribution company which harmed TGH's investment in that company. A tribunal established by the ICSID ruled in favour of TGH (the "First Award") and, in November 2020, Guatemala made a payment of approximately $38 million USD in full and final satisfaction of the First Award.

On September 23, 2016, TGH had filed a request for resubmission to arbitration seeking damages in addition to those awarded in the First Award. On May 13, 2020, an ICSID tribunal awarded TGH additional damages and costs against Guatemala of more than $35 million USD plus interest (the “Second Award”). TGH subsequently requested a reconsideration of the interest quantum awarded in connection with the Second Award. On October 16, 2020, the tribunal granted TGH’s request for additional interest. The additional amount was approximately $2 million USD. On February 12, 2021, Guatemala filed an application with ICSID for annulment of the Second Award. On March 31, 2021, ICSID constituted an ad hoc Committee to oversee the annulment proceeding. A three-day hearing was held before the ad hoc Committee beginning on July 27, 2022.

On November 28, 2022, TGH and Guatemala entered into a settlement agreement with respect to the Second Award. Pursuant to the settlement agreement, on December 15, 2022, Guatemala paid TGH $46 million USD and the parties agreed to settle all outstanding disputes, concluding this matter. This amount was recognized in “Other Income, net” on the Consolidated Statements of Income.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a potentially responsible party (“PRP”) for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as at December 31, 2022, TEC estimated its financial liability to be $17 million ($13 million USD), primarily at PGS. This estimate assumes that other involved PRPs are credit-worthy entities. This amount has been accrued and is primarily reflected in the long-term liability section under “Other long-term liabilities” on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC’s experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are believed to be currently credit-worthy and are likely to continue to be credit-worthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC’s actual percentage of the remediation costs. Other factors that could impact these estimates include additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in base rate proceedings.

Other Legal Proceedings

Emera and its subsidiaries may, from time to time, be involved in other legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Principal Financial Risks and Uncertainties

Emera believes the following principal financial risks could materially affect the Company in the normal course of business. Risks associated with derivative instruments and fair value measurements are discussed in note 15 and note 16.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has 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 established a Risk and Sustainability Committee ('RSC") in September 2021. 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.

Regulatory and Political Risk

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

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

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

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

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

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

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

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

General Economic Risk

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

Interest Rate Risk

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

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

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.

Commodity Price Risk

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

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

Regulated Utilities

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

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

Emera Energy Marketing and Trading

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

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

Income Tax Risk

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

D. Guarantees and Letters of Credit

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

TECO Energy has issued a guarantee in connection with SeaCoast's performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of $45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which was terminated on January 1, 2022. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's 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 up to $35 million USD relating to outstanding notes of GBPC. The guarantee for the notes will expire in May 2023.

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

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

The Company has standby letters of credit and surety bonds in the amount of $145 million USD (December 31, 2020 – $148 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually as required.

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

Collaborative Arrangements

For the years ended December 31, 2022 and 2021, 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. In 2022, NSPI recognized $12 million net expense (2021 – $18 million) in "Regulated fuel for generation and purchased power" and $3 million (2021 – $3 million) in OM&G.

28. CUMULATIVE PREFERRED STOCK

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

			December 31, 2022		December 31, 2021	
	Annual Dividend Per Share	Redemption Price per share	**Issued and Outstanding**	**Net Proceeds**	Issued and Outstanding	Net Proceeds
Series A	$ 0.5456	$ 25.00	**4,866,814**	**$ 119**	4,866,814	$ 119
Series B	Floating	$ 25.00	**1,133,186**	**$ 28**	1,133,186	$ 28
Series C	$ 1.1802	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 25.00	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0505	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Series H	$ 1.2250	$ 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	4.100	1.1802	2.65	August 15, 2023	25.00	Series D
Series F	4.202	1.0505	2.63	February 15, 2025	25.00	Series G
Minimum rate reset (3)(4)						
Series B	2.393	Floating	1.84	August 15, 2025	25.00	Series A
Series H	4.900	1.2250	4.90	August 15, 2023	25.00	Series I
Series J	4.250	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate						
Series E (5)	4.500	1.1250			25.00	
Series L (6)	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, 2023, February 15, 2025 and August 15, 2023, respectively. The reset dividend yield for Series I equals the Government of Treasury Bill Rate on the applicable reset date, plus 2.54 per cent.
(5) First Preferred Shares, Series E are redeemable at $25.00 per share.
(6) First Preferred Shares, Series L are redeemable at $26.00 on or after November 15, 2026 to November 15, 2027, decreasing $0.25 each year until November 15, 2030 and $25.00 per share thereafter.

First Preferred Shares are neither redeemable at the option of the shareholder nor have a mandatory redemption date. They are classified as equity and the associated dividends are deducted on the Consolidated Statements of Income before arriving at “Net income attributable to common shareholders” and shown on the Consolidated Statement of Equity as a deduction from retained earnings.

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares, for only so long as the dividends remain in arrears, will be entitled to attend any meeting of shareholders of the Company at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at any such meeting.

29. NON-CONTROLLING INTEREST IN SUBSIDIARIES

As at millions of dollars		**December 31 2022**		December 31 2021
Preferred shares of GBPC	**$**	**14**	$	14
Domlec (1)		**-**		20
	$	**14**	$	34

(1) On March 31, 2022, Emera disposed its interest in Domlec. For further details, refer to note 4.

Preferred shares of GBPC:

Authorized:
10,000 non-voting cumulative redeemable variable perpetual preferred shares.

			2022			2021
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 **2022**		2021
Changes in non-cash working capital:				
Inventory	**$**	**(214)**	$	(84)
Receivables and other current assets (1)		**(636)**		(364)
Accounts payable		**423**		289
Other current liabilities (2)		**193**		7
Total non-cash working capital	**$**	**(234)**	$	(152)

(1) Includes $(162) million related to the January 2023 settlement of NMGC gas hedges. 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 $172 million related to the Nova Scotia Cap-and-Trade program. For further detail, refer to note 7. 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.

Supplemental disclosure of cash paid (received):				
Interest	**$**	**699**	$	603
Income taxes	**$**	**67**	$	24
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**237**	$	214
Reclassification of long-term debt to short-term debt	**$**	**500**	$	-
Decrease in accrued capital expenditures	**$**	**(13)**	$	(45)
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	**$**	**(157)**	$	(108)

31. STOCK-BASED COMPENSATION

Employee Common Share Purchase Plan and Common Shareholders Dividend Reinvestment and Share Purchase Plan

Eligible employees may participate in Emera’s Employee Common Share Purchase Plan. As of December 31, 2022, the plan allows employees to make cash contributions of a minimum of $25 to a maximum of $20,000 CAD or $15,000 USD per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employees’ contributions to the plan.

The plan allows the reinvestment of dividends for all participants except for where it is prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares. As at December 31, 2022, Emera is in compliance with this requirement.

Compensation cost for shares issued under the Employee Common Share Purchase Plan for the year ended December 31, 2022 was $3 million (2021 – $3 million) and is included in OM&G on the Consolidated Statements of Income.

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan (“Dividend Reinvestment Plan”), which provides an opportunity for shareholders to reinvest dividends and purchase common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera’s common shares for common shares purchased in connection with the reinvestment of cash dividends. The discount was 2 per cent in 2022.

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, 2022, Emera is 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 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 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. 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 fair values per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

	2022	2021
Weighted average fair value per option	**$ 5.35**	$ 3.63
Expected term (1)	**5 years**	5 years
Risk-free interest rate (2)	**1.79 %**	0.60 %
Expected dividend yield (3)	**4.55 %**	5.00 %
Expected volatility (4)	**18.87 %**	19.14 %

(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 2022:

	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, 2021	2,590,304	$ 48.48	1,452,475	$ 3.18
Granted	467,100	58.26	467,100	5.35
Exercised	(203,525)	43.87	N/A	N/A
Vested	N/A	N/A	(571,175)	2.83
Options outstanding December 31, 2022	**2,853,879**	**$ 50.41**	**1,348,400**	**$ 4.08**
Options exercisable December 31, 2022 (2)(3)	**1,505,479**	**$ 46.59**		

(1) As at December 31, 2022, there was $4 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 (2021 – $3 million, 3 years).
(2) As at December 31, 2022, the weighted average remaining term of vested options was 5 years with an aggregate intrinsic value of $10 million (2021 – 6 years, $21 million).
(3) As at December 31, 2022, the fair value of options that vested in the year was $2 million (2021 – $1 million).

Compensation cost recognized for stock options for the year ended December 31, 2022 was $2 million (2021 – $2 million), which is included in OM&G on the Consolidated Statements of Income.

As at December 31, 2022, cash received from option exercises was $9 million (2021 – $14 million). The total intrinsic value of options exercised for the year ended December 31, 2022 was $4 million (2021 – $6 million). The range of exercise prices for the options outstanding as at December 31, 2022 was $32.35 to $60.03 (2021 – $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, 2022 is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2021	610,601	$ 39.22	614,365	$ 43.80
Granted including DRIP	76,252	52.42	104,465	57.89
Exercised	(59,630)	31.57	(54,572)	46.04
Outstanding and exercisable as at December 31, 2022	**627,223**	**$ 41.55**	**664,258**	**$ 45.83**

Compensation cost recovery recognized for employee and director DSU's for the year ended December 31, 2022 was $6 million (2021 – $9 million expense). Tax expense related to this compensation cost recovery for share units realized for the year ended December 31, 2022 was $2 million (2021 – $3 million tax recovery). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2022 for employees was $33 million (2021 – $39 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2022 for directors was $34 million (2021 – $39 million). Cash payments made during the year ended December 31, 2021 associated with the DSU plan was $8 million (2021 – $11 million).

Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios.

A summary of the activity related to employee PSUs for the year ended December 31, 2022 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate intrinsic value
Outstanding as at December 31, 2021	951,935	$ 48.60	$ 66
Granted including DRIP	242,462	59.30	
Exercised	(357,960)	42.85	
Forfeited	(145,991)	44.28	
Outstanding as at December 31, 2022	**690,446**	**$ 56.24**	**$ 40**

Compensation cost recognized for the PSU plan for the year ended December 31, 2022 was $18 million (2021 – $12 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2022 were $5 million (2021 – $3 million). Cash payments made during the year ended December 31, 2021 associated with the PSU plan was $24 million (2021 – $29 million).

Restricted Share Unit Plan

Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the RSU plan. RSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional RSUs. The RSU value varies according to the Emera common share market price.

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios.

A summary of the activity related to employee RSUs for the year ended December 31, 2022 is presented in the following table:

	Employee RSU	Weighted Average Grant Date Fair Value	Aggregate intrinsic value
Outstanding as at December 31, 2021	343,952	$ 54.64	$ 24
Granted including DRIP	180,426	59.30	
Exercised	(134)	54.63	
Forfeited	(15,776)	56.08	
Outstanding as at December 31, 2022	**508,468**	**$ 56.25**	**$ 30**

Compensation cost recognized for the RSU plan for the year ended December 31, 2022 was $9 million (2021 – $8 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2022 were $2 million (2021 – $2 million). Cash payments made during the year ended December 31, 2022 associated with the RSU plan was nil (2021– nil).

32. VARIABLE INTEREST ENTITIES

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the controlling financial interest of NSPML. When the critical milestones were achieved, Nalcor Energy was deemed the primary beneficiary of the asset for financial reporting purposes as it has authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link. Thus, Emera began recording the Maritime Link as an equity investment.

BLPC has established a Self-Insurance Fund (“SIF”), primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, the activities of the SIF are being conducted on behalf of ECI’s subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF’s operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. Any withdrawal of SIF fund assets by the Company would be subject to existing regulations. Emera’s consolidated VIE in the SIF is recorded as “Other long-term assets”, “Restricted cash” and “Regulatory liabilities” on the Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

The Company has identified certain long-term purchase power agreements that meet the definition of variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

The following table provides information about Emera’s portion of material unconsolidated VIEs:

As at	**December 31, 2022**		December 31, 2021	
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)	**$ 501**	**$ 6**	$ 533	$ 11

33. COMPARATIVE INFORMATION

These financial statements contain certain reclassifications of prior period amounts to be consistent with the current period presentation, with no effect on net income.

34. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company’s evaluation of events occurring subsequent to the balance sheet date through February 23, 2023, the date the financial statements were issued.