



Management’s Discussion & Analysis

As at February 23, 2026

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its consolidated subsidiaries and investments (collectively referred to as “Emera” or the “Company”) during the fourth quarter of, and for the full year of, 2025 relative to the same periods in 2024 and selected financial information for 2023; and its financial position as at December 31, 2025 relative to December 31, 2024. The Company’s activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

This MD&A should be read in conjunction with the Emera annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2025. Emera follows United States Generally Accepted Accounting Principles (“USGAAP” or “GAAP”). Additional information related to Emera, including the Company’s Annual Information Form, can be found on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov.

The accounting policies used by Emera’s rate-regulated entities may differ from those used by Emera’s non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At December 31, 2025, Emera’s rate-regulated subsidiaries and investments include:

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

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

TABLE OF CONTENTS

Forward-looking Information.....	2	Liquidity and Capital Resources.....	32
Introduction and Strategic Overview.....	3	Consolidated Cash Flow Highlights.....	32
Non-GAAP Financial Measures and Ratios.....	4	Working Capital.....	33
Consolidated Financial Review.....	7	Contractual Obligations.....	34
Significant Items Affecting Earnings.....	7	Forecasted Consolidated Capital Investments...	35
Consolidated Financial Highlights.....	8	Debt Management.....	35
Consolidated Income Statement Highlights.....	10	Credit Ratings.....	37
Business Overview and Outlook.....	13	Guaranteed Debt.....	37
Florida Electric Utility	13	Outstanding Stock Data.....	38
Canadian Electric Utilities	13	Pension Funding.....	39
Gas Utilities and Infrastructure.....	16	Off-Balance Sheet Arrangements.....	40
Other Electric Utilities	17	Dividend Payout Ratio.....	41
Other.....	18	Transactions with Related Parties.....	41
Consolidated Balance Sheet Highlights.....	19	Enterprise Risk and Risk Management.....	42
Other Developments.....	20	Risk Management including Financial	52
Financial Highlights.....	21	Instruments.....	
Florida Electric Utility	21	Disclosure and Internal Controls.....	54
Canadian Electric Utilities	23	Critical Accounting Estimates.....	54
Gas Utilities and Infrastructure.....	25	Changes in Accounting Policies and Practices.....	60
Other Electric Utilities	28	Future Accounting Pronouncements.....	60
Other.....	29	Summary of Quarterly Results.....	61

FORWARD-LOOKING INFORMATION

This MD&A contains “forward-looking information” and “forward-looking statements” (collectively, “FLI”) within the meaning of applicable Canadian and US securities laws, including the United States Private Securities Litigation Reform Act of 1995, which reflect the current view with respect to the Company’s expectations regarding future growth, results of operations, performance, earnings, capital investment, sales volumes, recovery of costs, timing of regulatory decisions, the expected timing and outcome of the pending sale of NMGC, the expected impact of Cybersecurity Incident (as defined herein) on the Company’s financial position and results of operations, information technology (“IT”) systems restoration, insurance recoveries, and business continuity processes as well as other matters relating to the Cybersecurity Incident, business prospects and opportunities, and may not be appropriate for other purposes. All such information and statements are made pursuant to safe harbour provisions contained in applicable securities legislation. The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecast”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “targets”, “will”, “would” and similar expressions are often intended to identify FLI, although not all FLI contains these identifying words. The FLI reflects management’s current beliefs and is based on information currently available to Emera’s management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

FLI is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the FLI. Factors that could cause results or events to differ from current expectations include, without limitation: regulatory and political risk; change in law risk; system operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital markets risk; changes in credit ratings; future dividend growth, rate base growth, and adjusted earnings per common share (“EPS”) growth; timing and costs associated with certain capital investments; expected impacts on Emera of challenges in the global economy; potential impacts of trade disputes and tariffs; estimated energy consumption rates; maintenance of adequate insurance coverage and receipt of proceeds; changes in customer energy usage patterns; developments in technology that could impact demand for electricity; climate risk; weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; supply chain risk; environmental risks; foreign exchange (“FX”); regulatory and government decisions, including changes to environmental legislation, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risks and costs associated with failure of IT infrastructure and cybersecurity incidents including IT systems restoration and business continuity processes; uncertainties associated with infectious diseases, pandemics and similar public health threats; risks associated with health and safety; market energy sales prices; labour relations; and availability of labour and management resources.

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

INTRODUCTION AND STRATEGIC OVERVIEW

Emera (TSX/NYSE: EMA) is a North American provider of energy services, owning and operating a portfolio of cost-of-service, rate-regulated electric and gas utilities. Its largest operations are in Florida, with additional operations in Atlantic Canada, New Mexico, and the Caribbean. Emera is headquartered in Halifax, Nova Scotia, Canada.

Emera’s business strategy is centred on continued investment in its regulated utilities, combined with a focus on operational excellence and efficiency, to safely and reliably deliver energy to its 2.7 million customers. Effective execution of these priorities supports predictable and growing earnings, cash flow, and dividends for shareholders.

Earnings opportunities in regulated utilities are a function of the magnitude of net investment in the utility (known as “rate base”), the amount of equity in the capital structure, and the targeted return on that equity (“ROE”), all as established and approved through regulation. Earnings are also affected by sales volumes and operating expenses. In 2025, Emera’s regulated cost-of-service utilities in Florida accounted for 67 per cent of average consolidated rate base, with Atlantic Canada comprising 25 per cent, and the Caribbean and New Mexico at 4 per cent each.

Emera’s capital investment plan is forecasted to be approximately \$20 billion from 2026 through 2030 and is focused on delivering value for customers through prudent investments in reliability and system resiliency, infrastructure modernization, expansion to address customer growth, integration of renewables, and technological innovations to deliver better customer experiences. It is anticipated that approximately 80 per cent of this capital investment will be made in Emera’s Florida utilities, necessitated by customer growth and system requirements at both TEC and PGS.

As at millions of dollars	2026	2027	2028	2029	2030	Total
Capital investment plan	\$ 4,020	\$ 3,730	\$ 4,140	\$ 4,180	\$ 4,330	\$ 20,400
Average consolidated rate base:						
US operations	\$ 23,180	\$ 25,100	\$ 27,140	\$ 29,300	\$ 31,480	
Canadian operations	7,340	7,660	7,990	8,320	8,580	
Total	\$ 30,520	\$ 32,760	\$ 35,130	\$ 37,620	\$ 40,060	

*Capital investment plan and average consolidated rate base exclude NMGC. For more information on the pending sale of NMGC, refer to “Other Developments” section.

Emera’s capital investment plan will be funded primarily through internally generated cash flows, debt raised at the operating company level consistent with regulated capital structures, equity issuances, and proceeds from the anticipated close of the NMGC transaction. Generally, Emera’s equity requirements are expected to be funded through the issuance of hybrid securities, and the issuance of common equity through Emera’s dividend reinvestment plan (“DRIP”) and its at-the-market program (“ATM program”). Maintaining investment-grade credit ratings is a core strategic priority of the Company.

Emera has increased dividends per common share paid for 19 consecutive years and has provided annual dividend growth guidance of one to two per cent. Emera anticipates average adjusted EPS growth of five to seven per cent through 2030, using 2024 as the base year, which will support continued reduction in the ratio of dividend payout to adjusted net income over time. For further information on the non-GAAP ratios “Adjusted EPS” and “Dividend Payout Ratio of Adjusted Net Income”, refer to the “Non-GAAP Financial Measures and Ratios” section.

NON-GAAP FINANCIAL MEASURES AND RATIOS

Emera uses financial measures and ratios that do not have standardized meaning under USGAAP and are calculated by adjusting certain GAAP measures for specific items. They may not be comparable to similar measures presented by other entities. These measures and ratios are discussed and reconciled below.

Adjusted Net Income, Adjusted EPS – Basic, and Dividend Payout Ratio of Adjusted Net Income

Emera calculates an adjusted net income attributable to common shareholders (“adjusted net income”) measure by excluding items below from net income attributable to common shareholders. Management believes excluding these items better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the business.

Emera calculates adjusted net income for the Florida Electric Utility, Gas Utilities and Infrastructure, Other Electric Utilities, and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. For more information refer to the Financial Highlights section for each of Florida Electric Utility, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

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

Adjusting Items Impacting All Periods

Mark-to-market (“MTM”) Adjustments:

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

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

Adjusting Items Impacting 2025 and 2024

Charges Related to the Pending Sale of NMGC:

On August 5, 2024, Emera entered into an agreement to sell NMGC. In Q2 2025, the Company recognized a \$71 million non-cash impairment charge, after-tax, and an additional loss of \$1 million in estimated transaction costs, after-tax, related to the pending sale. In Q3 2024, the Company recognized \$206 million in non-cash goodwill and other impairment charges, after-tax, and an additional loss of \$19 million in estimated transaction costs, after-tax, related to the pending sale. For further details, refer to the “Significant Items Affecting Earnings” and “Other Developments” sections.

Adjusting Items Impacting 2024

Gain on Sale of Emera’s Indirect Minority Interest in the Labrador Island Link (“Gain on sale of LIL”):

In Q2 2024, Emera recognized a \$107 million gain, after tax and transaction costs, on the sale of LIL. In Q4 2024, Emera recognized a \$22 million tax benefit related to the reversal of a prior year valuation allowance. A portion of the taxable capital gain on sale of LIL was offset by prior year loss carryforwards, of which the tax benefit was subject to a valuation allowance as at December 31, 2023. For further details refer to the “Significant Items Affecting Earnings” section.

Financing Structure Wind-Up:

In Q4 2024, Emera recognized a \$58 million tax benefit related to denied interest and financing expenses and the wind-up of a specific financing structure. For further details, refer to the “Significant Items Affecting Earnings” section.

Charges Related to Wind-Down Costs and Certain Asset Impairments:

In Q4 2024, the Company recognized \$26 million, after-tax, in wind-down costs and certain asset impairments, primarily at Block Energy LLC (“Block Energy”). For further details, refer to the “Significant Items Affecting Earnings” section.

Reconciliation of Net Income Attributable to Common Shareholders to Adjusted Net Income

For the millions of dollars (except per share amounts)	Three months ended December 31			Year ended December 31	
	2025	2024	2025	2024	2023
Net income attributable to common shareholders	\$ 68	\$ 154	\$ 1,014	\$ 494	\$ 978
MTM (loss) gain, after-tax (1)	(99)	(146)	41	(291)	169
Charges related to the pending sale of NMGC, after-tax (2)(3)	-	-	(72)	(225)	-
Gain on sale of LIL, after-tax (4)	-	22	-	129	-
Financing structure wind-up	-	58	-	58	-
Charges related to wind-down costs and certain asset impairments, after-tax (5)	-	(26)	-	(26)	-
Adjusted net income	\$ 167	\$ 246	\$ 1,045	\$ 849	\$ 809
EPS – basic	\$ 0.23	\$ 0.52	\$ 3.39	\$ 1.71	\$ 3.57
Adjusted EPS – basic	\$ 0.55	\$ 0.84	\$ 3.49	\$ 2.94	\$ 2.96

(1) Net of income tax recovery of \$39 million for the three months ended December 31, 2025 (2024 – \$57 million recovery) and \$17 million expense for the year ended December 31, 2025 (2024 – \$117 million recovery) (2023 – \$68 million expense).

(2) Represents (i) \$71 million non-cash impairment charge, after-tax and \$1 million in transaction costs, after-tax for the year ended December 31, 2025 and (ii) \$206 million in non-cash goodwill and other impairment charges, after-tax and \$19 million in transaction costs, after-tax for the year ended December 31, 2024.

(3) Net of income tax recovery of \$5 million for the year ended December 31, 2025 (2024 – \$21 million).

(4) Includes an income tax recovery of \$22 million for the three months ended December 31, 2024 and net of income tax expense of \$53 million for the year ended December 31, 2024.

(5) Net of income tax recovery of \$6 million for the three months and year ended December 31, 2024.

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization (“EBITDA”) and adjusted EBITDA are non-GAAP financial measures used by Emera. These financial measures are used by numerous investors and lenders to better understand cash flows and credit quality. EBITDA is useful to assess Emera’s operating performance and indicates the Company’s ability to service or incur debt, invest in capital, and finance working capital requirements. Adjusted EBITDA represents EBITDA absent the income effect of MTM adjustments, charges related to the pending sale of NMGC, the 2024 gain on sale of LIL, and the 2024 charges related to wind-down costs and certain asset impairments.

Reconciliation of Net Income to EBITDA and Adjusted EBITDA

For the millions of dollars	Three months ended December 31			Year ended December 31	
	2025	2024	2025	2024	2023
Net income (1)	\$ 87	\$ 173	\$ 1,090	\$ 568	\$ 1,045
Interest expense, net	268	248	1,032	973	925
Income tax (recovery) expense	(35)	(199)	81	(159)	128
Depreciation and amortization	335	296	1,294	1,162	1,049
EBITDA	\$ 655	\$ 518	\$ 3,497	\$ 2,544	\$ 3,147
MTM (loss) gain, excluding income tax	(138)	(203)	58	(408)	237
Charges related to the pending sale of NMGC, excluding income tax	-	-	(77)	(246)	-
Gain on sale of LIL, excluding income tax	-	-	-	182	-
Charges related to wind-down costs and certain asset impairments, excluding income tax	-	(32)	-	(32)	-
Adjusted EBITDA	\$ 793	\$ 753	\$ 3,516	\$ 3,048	\$ 2,910

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

The items detailed below have had a significant impact on net income attributable to common shareholders but have been excluded from adjusted net income as described in the section entitled “Non-GAAP Financial Measures and Ratios”.

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

For Q4 2025, MTM loss, after-tax, decreased \$47 million to \$99 million compared to \$146 million in Q4 2024, primarily due to a gain on Corporate FX hedges compared to a loss in prior year. For the year ended 2025, the 2024 MTM loss, after-tax, of \$291 million decreased \$332 million to a \$41 million MTM gain, after-tax primarily due to changes in existing positions and lower amortization of gas transportation assets at Emera Energy Services (“EES”) and a gain on Corporate FX hedges compared to a loss in prior year.

Charges Related to the Pending Sale of NMGC

2025:

In Q2 2025, Emera recognized a non-cash impairment charge of \$75 million (\$71 million after-tax, or \$0.24 per common share) related to the remeasurement of the NMGC disposal group to fair value (“FV”) less costs to sell. This was recorded in “Impairment charges” on the Consolidated Statements of Income and included in the Other Segment.

2024:

In Q3 2024, Emera recognized non-cash goodwill and other impairment charges of \$221 million (\$206 million after-tax, or \$0.72 per common share) related to the NMGC reporting unit. These charges were recorded in “Impairment charges” on the Consolidated Statements of Income and included in the Other and Gas Utilities and Infrastructure segments. Additionally, in Q3 2024, Emera recorded a loss of \$24 million (\$19 million after-tax, or \$0.06 per common share) in estimated transaction costs related to the pending sale. These transaction costs were included in “Other income, net” on the Consolidated Statements of Income and included in the Other segment.

For further details on the pending sale of NMGC, refer to the “Other Developments” section. For further details on the non-cash impairment and goodwill charges, refer to note 4 in the consolidated financial statements.

Gain on Sale of LIL

On June 4, 2024, Emera completed the sale of its LIL equity interest. A gain on sale of \$182 million after transaction costs (\$107 million, after tax and transaction costs, or \$0.37 per common share), was recognized in “Other Income, net” on the Consolidated Statements of Income in Q2 2024 and included in the Other segment. In Q4 2024, Emera recognized a \$22 million (\$0.08 per common share) tax benefit related to the reversal of a prior year valuation allowance. A portion of the taxable capital gain on the sale of the LIL equity interest was offset by prior year loss carryforwards, of which the tax benefit had been subject to a valuation allowance as at December 31, 2023. This tax benefit was recorded in “Income tax expense (recovery)” on the Consolidated Statements of Income in Q4 2024 and included in the Other segment. For further details on the transaction, refer to note 4 in the consolidated financial statements.

Financing Structure Wind-Up

During 2024, the Company incurred \$185 million of interest and financing expenses in connection with a specific financing structure. The current and future interest and financing expenses were expected to be denied under the Excessive Interest and Financing Expenses Limitation (“EIFEL”) legislation and, as a result, the financing structure was wound up. It was determined that Emera was more likely than not to realize the benefit of the current denied interest and financing expenses in future periods and therefore a \$54 million deferred income tax asset and related income tax benefit (\$0.19 per common share) was recorded during Q4 2024. In addition, Emera recognized a \$4 million income tax benefit (\$0.01 per common share) related to the reversal of a deferred income tax liability on the wind-up of the financing structure. The total tax benefit of \$58 million was recorded in “Income tax expense (recovery)” on the Consolidated Statements of Income and included in the Other segment during 2024.

Charges Related to Wind-Down Costs and Certain Asset Impairments

In Q4 2024, Emera recognized \$32 million (\$26 million after-tax, or \$0.09 per common share) in wind-down costs and certain asset impairments, primarily at Block Energy. These were recorded in “Other income, net” and “Impairment charges” on the Consolidated Statements of Income and included mainly in the Other segment.

Consolidated Financial Highlights

For the millions of dollars	Three months ended December 31			Year ended December 31	
	2025	2024	2025	2024	2023
Adjusted net income					
Florida Electric Utility	\$ 119	\$ 120	\$ 845	\$ 644	\$ 627
Canadian Electric Utilities	31	77	182	232	247
Gas Utilities and Infrastructure	76	87	276	267	214
Other Electric Utilities	15	21	43	48	35
Other	(74)	(59)	(301)	(342)	(314)
Adjusted net income	\$ 167	\$ 246	\$ 1,045	\$ 849	\$ 809
MTM (loss) gain, after-tax	(99)	(146)	41	(291)	169
Charges related to the pending sale of NMGC, after-tax	-	-	(72)	(225)	-
Gain on sale of LIL, after-tax	-	22	-	129	-
Financing structure wind-up	-	58	-	58	-
Charges related to wind-down costs and certain asset impairments, after-tax	-	(26)	-	(26)	-
Net income attributable to common shareholders	\$ 68	\$ 154	\$ 1,014	\$ 494	\$ 978

The following table highlights significant changes in adjusted net income from 2024 to 2025:

For the millions of dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2024	\$ 246	\$ 849
Operating Unit Performance		
Increased earnings at TEC year-over-year due to higher revenue from new base rates, customer growth, favourable weather, and the impact of a weaker CAD. These were partially offset by higher operating, maintenance and general expenses ("OM&G"), depreciation, interest expense, and income tax expense	(1)	201
Increased earnings at EES due to favourable weather conditions that led to higher natural gas prices and increased volatility that created profitable opportunities	17	50
Decreased earnings at NMGC quarter-over-quarter due to higher OM&G. Increased earnings year-over-year due to higher revenue from new base rates, partially offset by higher OM&G and depreciation expense	(12)	10
Decreased income from equity investments due to the sale of LIL in Q2 2024	-	(28)
Decreased earnings at NSPI quarter-over-quarter primarily due to lower income tax recovery due to the utilization of tax loss carryforwards recognized as a deferred income tax regulatory liability in 2024. For both quarter-over-quarter and year-over-year, decreased earnings due to higher OM&G and higher depreciation expense, partially offset by higher revenue due to favourable weather	(49)	(19)
Corporate		
Increased interest expense due to increased Corporate debt and the impact of a weaker CAD on USD interest expense, partially offset by lower interest rates	(4)	(14)
Decreased income tax recovery due to decreased deferred income tax asset valuation allowance adjustment	(27)	(9)
Other Variances	(3)	5
Adjusted net income – 2025	\$ 167	\$ 1,045

For the millions of dollars	2025	Year ended December 31	
		2024	2023
Operating cash flow before changes in working capital	\$ 2,559	\$ 2,194	\$ 2,336
Change in working capital	(757)	452	(95)
Operating cash flow	\$ 1,802	\$ 2,646	\$ 2,241
Investing cash flow	\$ (3,482)	\$ (2,218)	\$ (2,917)
Financing cash flow	\$ 1,841	\$ (818)	\$ 939

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

As at millions of dollars	2025	2024	December 31 2023
Total assets	\$ 44,817	\$ 42,951	\$ 39,480
Total long-term debt (including current portion) (1)	\$ 19,654	\$ 18,407	\$ 18,365

(1) Excludes NMGC balances classified as held for sale at December 31, 2025 and December 31, 2024. For further details, refer to the "Other Developments" section and note 4 in the consolidated financial statements.

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)	Three months ended December 31			Year ended December 31			Year ended December 31
	2025	2024	Variance	2025	2024	Variance	2023
Operating revenues	\$ 2,006	\$ 1,763	\$ 243	\$ 8,776	\$ 7,200	\$ 1,576	\$ 7,563
Operating expenses	1,731	1,524	(207)	6,801	6,120	(681)	5,769
Income from operations	\$ 275	\$ 239	\$ 36	\$ 1,975	\$ 1,080	\$ 895	\$ 1,794
Other income (expense), net	\$ 30	\$ (29)	\$ 59	\$ 165	\$ 203	\$ (38)	\$ 158
Income tax (recovery) expense	\$ (35)	\$ (199)	\$ (164)	\$ 81	\$ (159)	\$ (240)	\$ 128
Net income attributable to common shareholders	\$ 68	\$ 154	\$ (86)	\$ 1,014	\$ 494	\$ 520	\$ 978
Adjusted net income	\$ 167	\$ 246	\$ (79)	\$ 1,045	\$ 849	\$ 196	\$ 809
Weighted average shares of common stock outstanding (in millions)	301.2	294.1	7.1	299.2	289.1	10.1	273.6
EPS – basic	\$ 0.23	\$ 0.52	\$ (0.29)	\$ 3.39	\$ 1.71	\$ 1.68	\$ 3.57
EPS – diluted	\$ 0.25	\$ 0.52	\$ (0.27)	\$ 3.38	\$ 1.71	\$ 1.67	\$ 3.57
Adjusted EPS – basic	\$ 0.55	\$ 0.84	\$ (0.29)	\$ 3.49	\$ 2.94	\$ 0.55	\$ 2.96
Adjusted EBITDA	\$ 793	\$ 753	\$ 40	\$ 3,516	\$ 3,048	\$ 468	\$ 2,910
Dividends per common share declared	\$ 0.7325	\$ 0.7250	\$ 0.0075	\$ 2.9075	\$ 2.8775	\$ 0.0300	\$ 2.7875
Dividends per first preferred shares declared:							
Series A	\$ 0.7186	\$ 0.5456	\$ 0.1730	\$ 0.5456			\$ 0.5456
Series B	\$ 0.9451	\$ 1.6966	\$ (0.7515)	\$ 1.5583			\$ 1.5583
Series C	\$ 1.6085	\$ 1.6085	\$ -	\$ 1.2873			\$ 1.2873
Series E	\$ 1.1250	\$ 1.1250	\$ -	\$ 1.1250			\$ 1.1250
Series F	\$ 1.3406	\$ 1.0505	\$ 0.2900	\$ 1.0505			\$ 1.0505
Series H	\$ 1.5810	\$ 1.5810	\$ -	\$ 1.3140			\$ 1.3140
Series J	\$ 1.0625	\$ 1.0625	\$ -	\$ 1.0625			\$ 1.0625
Series L	\$ 1.1500	\$ 1.1500	\$ -	\$ 1.1500			\$ 1.1500

Trade Disputes and Tariffs

The extent of the future impact of trade disputes and tariffs on the Company's financial results and business operations continues to evolve, cannot be predicted at this time and will depend on future developments. To date, there has been no material financial impact on the Company. For information on risks associated with trade disputes and the imposition of tariffs, refer to the "Enterprise Risk and Risk Management" section.

Operating Revenues

For Q4 2025, operating revenues increased \$243 million compared to Q4 2024 and, excluding decreased MTM losses of \$19 million, increased \$224 million. The increase was due to higher storm cost recoveries at TEC and NSPI (offset in OM&G); new base rates at TEC; and higher marketing and trading margin at EES.

For the year ended December 31, 2025, operating revenues increased \$1,576 million compared to 2024 and, excluding increased MTM gains of \$369 million, increased \$1,207 million. The increase was due to higher storm cost recoveries at TEC and NSPI (offset in OM&G); new base rates at TEC and NMGC; the impact of a weaker CAD; higher fuel cost recoveries at TEC, NSPI and NMGC; higher marketing and trading margin at EES; and favourable weather at NSPI and TEC.

Operating Expenses

For Q4 2025, operating expenses increased \$207 million compared to Q4 2024. Excluding charges related to wind-down costs and certain asset impairments of \$4 million recognized in 2024, operating expenses increased \$211 million. For the year ended December 31, 2025, operating expenses increased \$681 million compared to 2024. Excluding the change in the charges related to the pending sale of NMGC of \$146 million and charges related to wind-down costs and certain asset impairments of \$4 million recognized in 2024, operating expenses increased \$831 million. These increases were primarily due to higher storm cost recognition of \$97 million quarter-over-quarter and \$350 million year-over-year at TEC and NSPI (offset in revenue); higher OM&G at NMGC and NSPI; and increased depreciation expense at TEC, PGS and NMGC. The year-over-year increase was also due to higher natural gas prices at TEC, PGS and NMGC; higher regulated fuel for generation and purchase power at NSPI; and the impact of a weaker CAD.

Other Income, net

For Q4 2025, other income, net increased \$59 million compared to Q4 2024, due to decreased FX losses and the 2024 charges related to wind-down costs and certain asset impairments.

For the year ended December 31, 2025, other income, net decreased \$38 million compared to 2024, due to the gain on sale of LIL in 2024, partially offset by higher FX gains in 2025, the 2024 charges related to wind-down costs and certain asset impairments and the 2024 transaction costs related to the pending sale of NMGC.

Income Tax Expense (Recovery)

For Q4 2025, income tax recovery decreased \$164 million compared to Q4 2024, due to the recognition of tax benefits associated with denied interest and financing expenses in the prior year, decreased deferred income tax asset valuation allowance adjustment and increased income before provision for income taxes.

For the year ended December 31, 2025, income tax expense increased \$240 million compared to 2024, due to increased income before provision for income taxes (excluding the gain on sale of LIL recognized in 2024 and the charges related to the pending sale of NMGC), recognition of tax benefits associated with denied interest and financing expenses in the prior year, and decreased deferred income tax asset valuation allowance adjustment. These were partially offset by the tax impact on the gain on sale of LIL recognized in 2024 and increased tax credits recognized at NSPI and TEC.

Net Income and Adjusted Net Income

Net income attributable to common shareholders for Q4 2025, compared to Q4 2024, was favourably impacted by the \$47 million decrease in MTM losses, the \$26 million charges related to wind-down costs and certain asset impairments in 2024, and unfavourably impacted by the \$58 million tax benefit related to a specific financing structure and its wind-up recognized in 2024 and the \$22 million valuation allowance reversal related to the gain on sale of LIL recognized in 2024. Excluding these changes, adjusted net income decreased \$69 million due to decreased earnings at NSPI and NMGC; and increased Corporate costs. These were partially offset by increased earnings at EES.

Net income attributable to common shareholders for the year ended 2025, as compared to the same period in 2024, was favourably impacted by the \$332 million decrease in MTM losses, the \$153 million change in the charges related to the pending sale of NMGC, and the \$26 million in charges related to wind-down costs and certain asset impairments and unfavourably impacted by the \$129 million gain on sale of LIL recognized in 2024 and the \$58 million tax benefit related to a specific financing structure and its wind-up recognized in 2024. Excluding these changes, adjusted net income increased \$206 million. The increase was primarily due to increased earnings at TEC, EES and NMGC. These were partially offset by lower equity earnings from LIL; higher Corporate costs; and lower earnings at NSPI.

EPS and Adjusted EPS – Basic

For Q4 2025, EPS - basic and adjusted EPS were lower than Q4 2024 due to the impact of lower earnings as discussed above and the impact of an increase in weighted average shares outstanding.

For the year ended December 31, 2025, EPS – basic and adjusted EPS were higher than 2024 due to the impact of higher earnings as discussed above, partially offset by the impact of an increase in weighted average shares outstanding.

Effect of Foreign Currency Translation

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

Results of foreign operations are translated at the weighted average rate of exchange, and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/USD exchange rates on net income attributable to common shareholders for 2025 and 2024 are as follows:

	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Weighted average CAD/USD	\$ 1.36	\$ 1.37	\$ 1.41	\$ 1.36
Period end CAD/USD exchange rate	\$ 1.37	\$ 1.44	\$ 1.37	\$ 1.44

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

For the millions of USD	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Florida Electric Utility	\$ 85	\$ 85	\$ 607	\$ 470
Gas Utilities and Infrastructure (1)(2)	50	56	179	178
Other Electric Utilities	11	15	31	35
Other segment (3)	(26)	(33)	(123)	(131)
Total (2)(4)	\$ 120	\$ 123	\$ 694	\$ 552

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.

(2) Excludes \$6 million USD, after-tax, in other impairment charges associated with the pending sale of NMGC for the year ended December 31, 2024.

(3) Includes Emera Energy’s USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.’s USD denominated debt.

(4) Excludes \$73 million USD in MTM losses, after-tax, for the three months ended December 31, 2025 (2024 – \$84 million USD MTM losses, after-tax) and \$5 million in USD MTM gain, after-tax, for the year ended December 31, 2025 (2024 – \$189 million USD MTM losses, after-tax).

In Q4 2025, the translation impact of a stronger CAD on USD denominated earnings decreased adjusted net income by \$3 million and decreased net income attributable to common shareholders by \$3 million, compared to the same period in 2024. For the year ended December 31, 2025, the impact of a weaker CAD on US denominated earnings increased adjusted net income by \$13 million and increased net income attributable to common shareholders by \$49 million, compared to 2024. Impacts of the changes in the translation of the CAD include the impacts of Corporate FX hedges used to mitigate translation risk of USD earnings in the Other segment.

BUSINESS OVERVIEW AND OUTLOOK

Florida Electric Utility

The Florida Electric Utility segment consists of TEC, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. With \$14.5 billion USD of assets and approximately 866,000 customers at December 31, 2025, TEC owns 6,771 megawatts (“MW”) of generating capacity, of which 78 per cent is natural gas fired, 21 per cent is solar and 1 per cent is energy storage. TEC owns approximately 2,200 kilometres of transmission facilities and 21,100 kilometres of distribution facilities. TEC meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

TEC’s approved regulated ROE range is 9.50 per cent to 11.50 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.50 per cent is used for the calculation of the return on investments for clauses.

TEC anticipates earning within its allowed ROE range in 2026. USD earnings are expected to be higher in 2026 than 2025 as a result of new base rates effective January 1, 2026, and continued customer growth.

On September 4, 2025, TEC petitioned the FPSC to increase base revenue by \$88 million USD to reflect the 2026 adjustment in accordance with its 2024 rate case decision. On November 4, 2025, the FPSC approved the adjustment, with new rates effective January 1, 2026.

On February 3, 2025, the FPSC issued the final order approving the 2024 rate case decision, effective January 1, 2025. For additional details on the 2024 rate case, refer to note 7 in Emera’s consolidated financial statements. In February 2025, a motion for reconsideration on certain aspects of the final order was filed by an intervening party with the FPSC. On May 6, 2025, the FPSC denied the motion for reconsideration, except with respect to immaterial calculation corrections, and the final order was issued on June 11, 2025. In March 2025, two intervening parties each filed a notice of appeal to the Florida Supreme Court regarding the outcome of TEC’s 2024 base rate proceeding. On January 12, 2026, the intervening parties filed their briefs related to the appeal. To date, the FPSC has not responded to the briefs.

On February 4, 2025, the FPSC approved TEC’s petition for the recovery of \$466 million USD of costs associated with Hurricane Idalia, Hurricane Debby, Hurricane Helene and Hurricane Milton, and the associated interest to replenish the storm reserve over an 18-month recovery period, which began in March 2025. The amount of cost-recovery is subject to a true-up mechanism with the FPSC. For additional details on the storm reserve, refer to note 7 in Emera’s consolidated financial statements.

In 2026, capital investment in the Florida Electric Utility segment is expected to be \$1.8 billion USD (2025 – \$1.6 billion USD), including allowance for funds used during construction (“AFUDC”). Capital projects include investment in generation reliability projects and storm hardening, grid modernization, and transmission expansion.

Canadian Electric Utilities

The Canadian Electric Utilities segment includes NSPI and NSPML. NSPI is a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia. NSPML is a 100 per cent equity interest in the Maritime Link Project (“Maritime Link”), a transmission project between the island of Newfoundland and Nova Scotia.

NSPI

With \$8.1 billion of assets and approximately 565,000 customers at December 31, 2025, NSPI owns 2,422 MW of generating capacity, of which 44 per cent is coal and/or oil-fired; 28 per cent is natural gas and/or oil; 19 per cent is hydro, wind, or solar; 7 per cent is petroleum coke (“petcoke”) and 2 per cent is biomass-fueled generation. In 2025, NSPI began operations of two 50 MW grid-scale battery facilities to enhance reliability. In addition, NSPI has contracts to purchase renewable energy from independent power producers (“IPPs”) and community feed-in tariff (“COMFIT”) participants, which own 573 MW of capacity. NSPI also has rights to 153 MW of Maritime Link capacity, representing Newfoundland and Labrador Hydro’s (“NLH”) Nova Scotia Block (“NS Block”) delivery obligations, as discussed below. NSPI owns approximately 5,400 kilometres of transmission facilities and 28,700 kilometres of distribution facilities.

NLH is obligated to provide NSPI with approximately 900 Gigawatt hours (“GWh”) of energy annually over 35 years. In addition, until March 31, 2026, NLH is obligated to provide approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from NLH through the Energy Access Agreement. The Energy Access Agreement enables NSPI to access a market-priced bid from NLH for up to 1.8 Terawatt hours (“TWh”) of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

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

Assuming new base rates are approved by the NSEB in the general rate application (“GRA”) and are generally consistent with the settlement agreement, NSPI anticipates earning at the low end of its allowed ROE in 2026 and expects earnings in 2026 to be higher than 2025. Sales volumes are expected to be higher in 2026 than 2025.

On September 18, 2025, NSPI filed a consensus GRA with the NSEB, reflecting a settlement agreement reached with customer representatives. The GRA proposes average annual rate increases of 1.8 per cent in 2026 and 2.4 per cent in 2027. The proposed rates would result in annual revenue (fuel and non-fuel) increases of \$62 million in 2026 and \$108 million in 2027. The hearing for the matter concluded in January 2026 and a decision by the NSEB is expected by early Q2 2026.

On March 5, 2025, NSPI, the Canada Infrastructure Bank (“CIB”) and the Wskijinu’k Mtmo’taqnuow Agency (“WMA”) announced the Wasoqonatl transmission line project to create a reliability intertie between Nova Scotia and New Brunswick. The project is owned by a new regulated utility, WTI, which is wholly-owned by a newly formed limited partnership between NSPI, CIB and WMA. NSPI is responsible for providing construction, operation, maintenance and administrative services to WTI. NSPI has a 50 per cent indirect voting interest in WTI which is recorded as an “Investments subject to significant influence” on Emera’s Consolidated Balance Sheets.

In 2026, capital investment is expected to be \$720 million (2025 – \$712 million), including AFUDC. NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

Environmental Legislation and Regulations

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

Nova Scotia Energy Reform Act:

On October 15, 2025, the Nova Scotia Independent Energy System Operator (“IESO Nova Scotia”) announced that the organization will be phased in over two phases during an 18-month period. On December 1, 2025, the first phase was complete following the transfer of system planning and interconnection functions. The second phase is expected to be complete in 2027 as IESO Nova Scotia assumes responsibility for system operations. The establishment of IESO Nova Scotia follows Bill 404 - Energy Reform (2024) Act enacted in April 2024, which established the NSEB, and phased transition to IESO Nova Scotia.

Renewable Energy Regulations (“RER”):

On May 26, 2023, NSPI initiated an appeal, through a proceeding with the NSEB, of the \$10 million penalty levied on NSPI by the Province for non-compliance with the RER compliance period ending in 2022. The hearing concluded in 2025 and NSPI is awaiting a decision.

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.

Equity earnings from NSPML in 2026 are expected to be consistent with 2025. The NSPML investment is recorded as “Investments subject to significant influence” on Emera’s Consolidated Balance Sheets.

The Maritime Link assets entered service on January 15, 2018, enabling the transmission of energy between Newfoundland and Nova Scotia, improved reliability and ancillary benefits, supporting the efficiency and reliability of energy in both provinces. NLH’s NS Block delivery obligations commenced on August 15, 2021 and will be delivered over the next 35 years pursuant to the project agreements.

On December 23, 2025, NSPML received an interim order from the NSEB to collect up to \$199 million from NSPI for the recovery of costs associated with the Maritime Link in 2026, subject to a monthly holdback of up to \$4 million. A final decision from the NSEB is pending. There was no holdback recorded for the year ended December 31, 2025.

On February 4, 2026, NSPML submitted an application with the NSEB requesting the termination of the holdback mechanism. A decision is anticipated in Q3 2026.

In 2026, the capital investment at NSPML is expected to be approximately \$40 million (2025 – \$7 million).

Gas Utilities and Infrastructure

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

On August 5, 2024, Emera announced an agreement to sell NMGC. As a result of the pending sale, NMGC's assets and liabilities were classified as held for sale as of Q3 2024. The public hearing was held in November 2025. The transaction is expected to close in the first half of 2026. For more information on the pending transaction, refer to the "Other Developments" section.

PGS

With \$3.3 billion USD of assets and approximately 523,000 customers, the PGS system includes approximately 25,600 kilometres of natural gas mains and 14,800 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2 billion therms in 2025.

Beginning in 2026, the approved ROE range for PGS is 9.30 per cent to 11.30 per cent (2025 – 9.15 per cent to 11.15 per cent) based on an allowed equity capital structure of 54.7 per cent (2025 – 54.7 per cent). An ROE of 10.30 per cent (2025 – 10.15 per cent) is used for the calculation of return on investments for clauses.

PGS anticipates earning within its allowed ROE range in 2026. USD earnings are expected to be higher in 2026 than 2025, as a result of new base rates effective January 1, 2026, and continued customer growth.

On March 31, 2025, PGS filed a rate case with the FPSC for new rates to become effective January 1, 2026. On August 13, 2025, PGS and the intervening parties filed a settlement agreement with the FPSC for a \$67 million USD increase in 2026 annual base rates, which includes \$7 million USD from the cast iron and bare steel replacement rider, and additional adjustments of \$25 million USD in 2027 and up to \$5 million USD in 2028 (subject to FPSC approval). This reflects a 10.30 per cent midpoint ROE and 54.7 per cent equity thickness. On October 31, 2025, the FPSC issued the final order approving the settlement.

In 2026, capital investment is expected to be approximately \$445 million USD (2025 – \$323 million USD), including AFUDC. PGS will make investments to maintain the reliability of their systems and support customer growth.

NMGC

With \$1.6 billion USD of assets and approximately 553,000 customers, NMGC's system includes approximately 2,300 kilometres of transmission pipelines and 18,200 kilometres of distribution pipelines. Annual natural gas throughput was approximately 1 billion therms in 2025.

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

NMGC's USD earnings contribution to Emera in 2026 are expected to be lower than in 2025 as a result of the pending sale of NMGC, which is expected to close in the first half of 2026.

Other Electric Utilities

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

Other Electric Utilities’ USD earnings in 2026 are expected to be consistent with the prior year.

In 2026, capital investment in the Other Electric Utilities segment is expected to be approximately \$110 million USD (2025 – \$67 million USD), including AFUDC, primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

BLPC

With \$547 million USD of assets and approximately 137,000 customers, BLPC owns 243 MW of generating capacity, of which 96 per cent is oil-fired and 4 per cent is solar. BLPC owns approximately 200 kilometres of transmission facilities and 4,000 kilometres of distribution facilities. BLPC’s approved regulated return on rate base is 10 per cent.

In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately \$1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities totalling approximately \$71 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the “Motion”) and applied for a stay of the FTC’s decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

On December 1, 2023, BLPC appealed certain aspects of the FTC’s February 15 and November 20, 2023 decisions to the Supreme Court of Barbados in the High Court of Justice (the “Court”) and requested that they be stayed. On December 11, 2023, the Court granted the stay. BLPC’s position is that the FTC made errors of law and jurisdiction in their decisions and believes the success of the appeal is probable, and as a result, the adjustments to BLPC’s final rates and rate base, including any adjustments to regulatory assets and liabilities, have not been recorded at this time. The appeal was heard in December 2025, and will continue in early 2026. A decision is expected in 2026.

BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In November 2025, the Government of Barbados and BLPC agreed to new Transmission, Distribution, Sales and Dispatch (“T&D”) and Generation and Energy Storage (“G&S”) licenses. The G&S license will be valid until 2047, unless otherwise extended. The T&D License will be valid for 30 years. These new non-exclusive licenses have since been signed and will become effective upon the repeal of the existing license. BLPC continues to operate under its current statutory authority while preparing for the transition to the new licensing framework.

GBPC

With \$378 million USD of assets and approximately 20,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 100 kilometres of transmission facilities and 1,000 kilometres of distribution facilities. GBPC’s approved regulatory return on rate base is 8.52 per cent.

On August 1, 2024, as required by the GBPA Operating Protocol and Regulatory Framework Agreement, GBPC filed a rate plan proposal. A review of the proposal by the GBPA is expected to commence in the first half of 2026.

On June 1, 2024, the Electricity Act, 2024 took effect. The legislation purports to remove the jurisdiction of the GBPA over GBPC and to have the Utilities Regulation and Competition Authority (“URCA”), another Bahamian regulator, regulate GBPC. In 2024, URCA filed a claim in the Supreme Court of the Bahamas, seeking an order that the GBPA be prohibited and restrained from considering and/or approving any adjustment to rates sought by GBPC. URCA contends that it has regulatory authority over electricity provision on Grand Bahama pursuant to the Electricity Act. Management does not expect that the outcome of the proceedings will have a material impact to Emera.

Other

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

Business operations in the Other segment include Corporate; Emera Energy Services (“EES”), a physical energy marketing and trading business; and a 50 per cent joint venture interest in Bear Swamp, a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts.

Corporate includes certain corporate-wide functions including executive management, strategic planning, treasury services, legal, financial reporting, tax planning, corporate business development, corporate governance, investor relations, risk management, insurance, acquisition and disposition related costs, gains or losses on select assets sales, and corporate human resource activities. It includes interest revenue on intercompany financings and interest expense on corporate debt in both Canada and the US.

Earnings from EES are generally dependent on market conditions. In particular, volatility in natural gas and electricity markets, which can be influenced by weather, local supply constraints and other supply and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 usually providing the greatest opportunity for earnings. EES is generally expected to deliver annual adjusted net income of \$15 million USD to \$30 million USD. In light of strong market conditions in early 2026, EES expects USD adjusted net income for 2026 to be in line with 2025 results.

The adjusted net loss from the Other segment in 2026 is expected to be consistent with 2025.

In 2026, capital investment is expected to be approximately \$10 million (2025 – \$6 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2024 and December 31, 2025 include:

millions of dollars	Total Increase (Decrease)	Explanation of Increase (Decrease)
Assets		
Cash and cash equivalents	\$ 153	Increased due to higher cash from operations, increased proceeds under committed credit facilities at TEC, proceeds from debt issuances at TEC, and proceeds from common shares issued. These were partially offset by investment in property, plant and equipment ("PP&E"), repayment of committed credit facilities at TECO Finance, Inc. ("TECO Finance") and Emera, and dividends paid on Emera common stock
Regulatory assets (current and long-term)	(229)	Decreased due to lower storm cost recovery assets at TEC and NSPI and the effect of FX translation of Emera's non-Canadian affiliates. These were partially offset by higher deferrals related to the fuel adjustment mechanism ("FAM") and the deferred income tax regulatory asset at NSPI
Receivables and other assets (current and long-term)	984	Increased trade receivables due to higher commodity prices at EES, higher trade receivables at NSPI and TEC, higher right of use assets related to new finance leases at TEC, and increased pension assets due to higher return on assets in 2025 at TEC
Assets held for sale (current and long-term), net of liabilities (1)	(101)	Decreased primarily due to non-cash impairment charge recognized in 2025, and the effect of FX translation of NMGC
PP&E, net of accumulated depreciation and amortization	1,240	Increased due to capital additions in excess of depreciation, partially offset by the effect of FX translation of Emera's non-Canadian affiliates
Goodwill	(278)	Decreased due to the effect of FX translation of Emera's non-Canadian affiliates
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	\$ 1,654	Increased due to issuance of long-term debt at EUSHI Finance Inc. ("EUSHI Finance") and TEC, proceeds from the issuance of a non-revolving term credit facility at NSPI, and higher utilization of committed credit facilities at TEC. These were partially offset by the effect of FX translation of Emera's non-Canadian affiliates and repayment of committed credit facilities at Corporate and TECO Finance
Deferred income tax liabilities, net of deferred income tax assets	156	Increased due to tax deductions in excess of accounting depreciation related to PP&E and changes in pension and post-retirement assets and liabilities. This was partially offset by increased tax credits at TEC and the effect of FX translation of Emera's non-Canadian affiliates
Regulatory liabilities (current and long-term)	(211)	Decreased due to lower FAM liability at NSPI, lower cost recovery clause liabilities and lower deferred income tax regulatory liabilities at TEC, and the effect of FX translation of Emera's non-Canadian affiliates
Other liabilities (current and long-term)	96	Increased due to finance leases entered into at TEC and timing of interest payments at Corporate
Common stock	345	Increased due to shares issued
Accumulated other comprehensive income	(388)	Decreased due to the effect of FX translation of Emera's non-Canadian affiliates, partially offset by higher unrecognized pension and post-retirement benefit costs due to higher investment returns and favourable changes in actuarial assumptions and amortization at NSPI
Retained earnings	146	Increased due to net income in excess of dividends paid

(1) On August 5, 2024, Emera announced the sale of NMGC. As a result, NMGC's assets and liabilities were classified as held for sale beginning in Q3 2024. For further details, refer to the "Other Developments" section and note 4 in the consolidated financial statements.

OTHER DEVELOPMENTS

Increase in Common Dividend

On September 25, 2025, the Emera Board of Directors approved an increase in the annual common share dividend rate to \$2.93 from \$2.90 per common share. The first payment was effective November 14, 2025.

Cybersecurity Incident

On April 25, 2025, Emera and NSPI discovered a cybersecurity incident involving unauthorized access into certain parts of its Canadian IT network and servers supporting portions of its business applications (the "Cybersecurity Incident"). There was no disruption to the Canadian physical operations or Emera's US or Caribbean utilities' operations.

The Company implemented business continuity processes for certain impacted business and administrative functions at its Canadian affiliates. The systematic restoration of affected IT systems and corresponding transition away from business continuity processes continues to progress in a planned, controlled and phased approach. For more information on the impact on internal controls over financial reporting, refer to the "Disclosure and Internal Controls" section. The Company maintains cyber insurance coverage and is working with its insurer on the claims process. At this time, the Cybersecurity Incident is not expected to have a material impact on the Company's financial position or results of operations. For information on risks associated with cybersecurity incidents generally, refer to the "Enterprise Risk and Risk Management" section.

Pending Sale of NMGC

On August 5, 2024, Emera entered into an agreement to sell its indirect wholly-owned subsidiary NMGC for a total enterprise value of approximately \$1.3 billion USD, consisting of cash proceeds and the transfer of debt and customary closing adjustments. As a result of the pending sale, NMGC's assets and liabilities were classified as held for sale in Q3 2024 and the carrying value of the assets and liabilities were adjusted to FV less cost to sell. The public hearing was held in November 2025. The transaction is expected to close in the first half of 2026.

At each reporting date, the Company performs an assessment of the FV of the disposal group by comparing the FV of expected transaction proceeds, less costs to sell, to the carrying value of net assets, including goodwill ("carrying amount"). On June 30, 2025, the Company remeasured the NMGC disposal group at the lower of its carrying amount and FV less costs to sell. As a result of the change in the expected timing of the transaction close, a non-cash impairment charge of \$75 million (\$71 million, after-tax), or \$55 million USD (\$52 million USD, after-tax), was recorded in "Impairment charges" on the Consolidated Statements of Income in Q2 2025. An additional loss for estimated future transaction costs of \$2 million (\$1 million after-tax) was recorded in "Other income, net" on the Consolidated Statements of Income in Q2 2025. There were no additional adjustments recorded in 2025.

The Company will continue to record depreciation on the NMGC assets through the transaction closing date, as the depreciation continues to be reflected in customer rates and will be reflected in the carryover basis of the assets when sold. Depreciation and amortization of \$97 million (\$70 million USD) was recorded on these assets from August 5, 2024, the date they were classified as held for sale, through December 31, 2025. Of the \$97 million (\$70 million USD) recorded to date, \$71 million (\$51 million USD) was recorded in 2025.

US One Big Beautiful Bill Act (“OBBBA”)

On July 4, 2025, the OBBBA was signed into law. The OBBBA makes permanent many of the expired and expiring tax provisions originally enacted in the Tax Cuts and Jobs Act of 2017. It also includes significant changes in future years to the timing and availability of several clean energy tax credits previously enacted in the Inflation Reduction Act, including the investment tax credit and production tax credit. On August 15, 2025, the Internal Revenue Service released guidance on determining when wind and solar projects have begun construction for purposes of qualifying for these tax credits. Emera’s 2025 financial statements were not materially impacted as a result of the enacted changes. Emera will continue to evaluate the future impact as additional information and guidance becomes available.

New York Stock Exchange (“NYSE”) Listing

Emera filed a registration statement dated May 1, 2025 on Form 40-F with the US Securities and Exchange Commission (“SEC”) to register its common shares under Section 12 of the Securities Exchange Act of 1934. Emera subsequently completed the listing of its common shares on the NYSE and commenced trading on May 28, 2025. Emera’s common shares continue to be listed and traded on the Toronto Stock Exchange.

Appointments

Executive

Effective March 1, 2026, Vivek Sood will become President and CEO of NSPI, succeeding Peter Gregg. Most recently, Mr. Sood retired as Executive Vice President, Related Businesses from Sobeys Inc. in 2024, and has served as a member of the NSPI Board of Directors since June 2024.

Effective December 1, 2025, Jared Green became Emera’s new Chief Financial Officer, succeeding Greg Blunden. Mr. Green most recently served as President and Chief Executive Officer of TriSummit Utilities (previously AltaGas Canada).

Board of Directors

Effective September 17, 2025, Isabelle Courville joined the Emera Board of Directors. Ms. Courville is Chair of the Board of Canadian Pacific Kansas City and previously served as President of Hydro-Québec Distribution and Hydro Québec TransÉnergie, as well as President of Bell Canada’s Enterprise Group.

FINANCIAL HIGHLIGHTS

Florida Electric Utility

For the millions of USD (except as indicated)	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Operating revenues – regulated electric	\$ 706	\$ 582	\$ 3,115	\$ 2,526
Regulated fuel for generation and purchased power	\$ 150	\$ 151	\$ 703	\$ 622
Contribution to consolidated adjusted net income	\$ 85	\$ 85	\$ 607	\$ 470
Contribution to consolidated adjusted net income - CAD	\$ 119	\$ 120	\$ 845	\$ 644
Charges related to wind-down costs and certain asset impairments, after-tax (1)	\$ -	\$ (2)	\$ -	\$ (2)
Contribution to consolidated net income	\$ 85	\$ 83	\$ 607	\$ 468
Contribution to consolidated net income – CAD	\$ 119	\$ 117	\$ 845	\$ 641
Average fuel costs in dollars per MWh	\$ 31	\$ 31	\$ 32	\$ 28

(1) Net of income tax recovery of \$1 million for the three months and year ended December 31, 2024.

The impact of the change in FX rates on CAD earnings was minimal for the three months ended December 31, 2025, and increased CAD earnings by \$16 million for the year ended December 31, 2025.

Net Income

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

For the millions of USD	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2024	\$ 83	\$ 468
Increased operating revenues primarily due to storm cost recovery revenue (offset in OM&G), new base rates, higher regulatory deferral revenue and customer growth. These were partially offset by unfavourable weather of \$10 million quarter-over-quarter. Year-over-year increase was also due to favourable weather of \$10 million	124	589
Increased fuel for generation and purchased power year-over-year due to higher natural gas prices and higher purchased power	1	(81)
Increased OM&G due to higher storm cost recognition (offset in revenue), higher costs for employee benefits, operations related to solar investments, and software maintenance. These were partially offset by the timing of recognition of regulatory deferrals	(88)	(246)
Increased depreciation and amortization due to facilities and capital projects placed in service	(17)	(51)
Increased interest expense due to higher borrowings	(9)	(25)
Increased state and municipal taxes due to higher revenues and higher taxable plant in service	(10)	(28)
Increased income tax expense year-over-year primarily due to higher income before provision for income taxes, partially offset by higher benefit from production tax credits and increased amortization of deferred investment tax credits	2	(32)
Other	(1)	13
Contribution to consolidated net income – 2025	\$ 85	\$ 607

Operating Revenues – Regulated Electric

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

	Electric Revenues (millions of USD)		Electric Sales Volumes (Gigawatt hours ("GWh"))	
	2025	2024	2025	2024
Residential	\$ 1,786	\$ 1,507	10,309	10,269
Commercial	822	686	6,536	6,481
Industrial	195	162	2,105	2,019
Other (1)	312	171	2,377	2,276
Total	\$ 3,115	\$ 2,526	21,327	21,045

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

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2025	2024
Natural gas	17,470	18,027
Solar	2,419	2,250
Purchased power	2,004	1,569
Coal	46	32
Total	21,939	21,878

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

Regulatory Environment

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

Canadian Electric Utilities

For the millions of dollars (except as indicated)	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Operating revenues – regulated electric	\$ 504	\$ 479	\$ 1,944	\$ 1,855
Regulated fuel for generation and purchased power (1)(2)	\$ 269	\$ (216)	\$ 1,065	\$ 509
Contribution to consolidated net income	\$ 31	\$ 77	\$ 182	\$ 232
Average fuel costs in dollars per MWh (2)	\$ 89	\$ (73)	\$ 93	\$ 45

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

(2) Regulated fuel for generation and purchased power and average fuel costs for 2024 include a \$486 million refund of previous NSPML assessment payments ("NSPML Refund"), which decreased average fuel costs by \$164 per MWh and \$43 per MWh for the three months and year ended December 31, 2024, respectively. For more information on the NSPML Refund, refer to note 7 in the consolidated financial statements.

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

For the millions of dollars	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
NSPI	\$ 22	\$ 71	\$ 141	\$ 160
Equity investment in NSPML	9	6	41	44
Equity investment in LIL	-	-	-	28
Contribution to consolidated net income	\$ 31	\$ 77	\$ 182	\$ 232

Net Income

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

For the millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2024	\$ 77	\$ 232
Increased operating revenues at NSPI due to higher fuel and storm cost recoveries, favourable weather, and increased residential and commercial sales volumes, partially offset by lower industrial sales volumes	25	89
Increased regulated fuel for generation and purchased power at NSPI due to the 2024 NSPML Refund ⁽¹⁾ , changes in generation mix, and higher sales volumes, partially offset by lower commodity prices	(485)	(556)
Decreased FAM deferral at NSPI primarily due to the 2024 NSPML Refund ⁽¹⁾	472	511
Increased OM&G at NSPI quarter-over-quarter due to increased storm costs and costs related to the Cybersecurity Incident. Year-over-year increased due to higher costs for transmission and distribution operations, costs related to the Cybersecurity Incident and power generation operations, partially offset by higher administrative overhead allocation to PP&E	(21)	(49)
Increased depreciation and amortization due to increased PP&E in service	(4)	(16)
Decreased income from equity investments due to the sale of equity interest in LIL	-	(28)
Decreased income tax recovery quarter-over-quarter at NSPI primarily due to the utilization of tax loss carryforwards recognized as a deferred income tax regulatory liability in the prior year and decreased tax deductions in excess of accounting depreciation related to PP&E	(35)	4
Other	2	(5)
Contribution to consolidated net income – 2025	\$ 31	\$ 182

(1) For more information on the \$486 million NSPML Refund in 2024, refer to note 7 in the consolidated financial statements.

NSPI

Operating Revenues – Regulated Electric

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

	Electric Revenues (millions of dollars)		Electric Sales Volumes (GWh)	
	2025	2024	2025	2024
Residential	\$ 1,073	\$ 997	5,292	5,096
Commercial	522	499	3,084	3,046
Industrial	270	276	2,098	2,217
Other	43	41	231	222
Total	\$ 1,908	\$ 1,813	10,705	10,581

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2025	2024
Coal	4,370	3,347
Natural gas	1,403	2,317
Purchased power	391	620
Oil	295	132
Petcoke	279	374
Total non-renewables	6,738	6,790
Purchased power - IPP, COMFIT and imports	3,707	3,464
Wind, hydro and solar	855	932
Biomass	174	140
Total renewables	4,736	4,536
Total production volumes	11,474	11,326

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

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

Regulatory Environment – NSPI

NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia (“Public Utilities Act”) and is subject to regulation by the NSEB. The Public Utilities Act gives the NSEB supervisory powers over NSPI's operations and expenditures. 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 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 NSEB's request. For further details on NSPI's regulatory environment and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Gas Utilities and Infrastructure

On August 5, 2024, Emera announced an agreement to sell NMGC. As a result of the pending sale, NMGC's assets and liabilities were classified as held for sale beginning in Q3 2024. The public hearing was held in November 2025. The transaction is expected to close in the first half of 2026, subject to certain approvals, including regulatory approval by the NMPRC. For more information on the pending transaction, refer to the “Other Developments” section.

For the millions of USD (except as indicated)	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Operating revenues – regulated gas (1)	\$ 327	\$ 317	\$ 1,235	\$ 1,160
Operating revenues – non-regulated	4	3	17	15
Total operating revenue	\$ 331	\$ 320	\$ 1,252	\$ 1,175
Regulated cost of natural gas	\$ 73	\$ 81	\$ 318	\$ 289
Contribution to consolidated adjusted net income	\$ 55	\$ 61	\$ 196	\$ 194
Contribution to consolidated adjusted net income – CAD	\$ 76	\$ 87	\$ 276	\$ 267
Charges related to the pending sale of NMGC, after-tax (2)	\$ -	\$ -	\$ -	\$ (6)
Contribution to consolidated net income	\$ 55	\$ 61	\$ 196	\$ 188
Contribution to consolidated net income – CAD	\$ 76	\$ 87	\$ 276	\$ 259

(1) Operating revenues – regulated gas includes \$12 million of finance income from Brunswick Pipeline (2024 – \$12 million) for the three months ended December 31, 2025 and \$46 million (2024 – \$46 million) for the year ended December 31 2025; however, it is excluded from the gas revenues and cost of natural gas analysis below.

(2) Includes an other impairment charge, net of income tax recovery of \$2 million for the year ended December 31, 2024.

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

For the millions of USD	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
PGS	\$ 31	\$ 28	\$ 117	\$ 120
NMGC	15	23	45	39
Other	9	10	34	35
Contribution to consolidated adjusted net income	\$ 55	\$ 61	\$ 196	\$ 194

The impact of the change in FX rates on CAD earnings was minimal for the three months ended December 31, 2025, and increased CAD earnings by \$7 million for the year ended December 31, 2025.

Net Income

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

For the millions of USD	Three months ended	Year ended
	December 31	December 31
Contribution to consolidated net income – 2024	\$ 61	\$ 188
Increased gas revenues due to higher fuel revenue and higher off-system sales at PGS and new base rates at NMGC	11	77
Decreased cost of natural gas quarter-over-quarter primarily due to timing of profit sharing with customers related to asset management agreements at NMGC. Increased cost of natural gas year-over-year due to higher natural gas prices at PGS	8	(29)
Increased OM&G primarily due to higher labour costs at NMGC	(16)	(20)
Increased depreciation primarily due to capital projects in service at PGS and NMGC	(4)	(14)
Other	(5)	(6)
Contribution to consolidated net income – 2025	\$ 55	\$ 196

Operating Revenues – Regulated Gas

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

	Gas Revenues (millions of USD)		Gas Volumes (millions of Therms)	
	2025	2024	2025	2024
Residential	\$ 548	\$ 520	394	410
Commercial	377	362	875	824
Industrial (1)	73	69	1,568	1,620
Other (2)	191	163	313	278
Total (3)	\$ 1,189	\$ 1,114	3,150	3,132

(1) Industrial gas revenue includes sales to power generation customers.

(2) Other gas revenue includes off-system sales to other utilities and various other items.

(3) Total gas revenue excludes \$46 million of finance income from Brunswick Pipeline (2024 – \$46 million).

Regulated Cost of Natural Gas

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

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

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

	Gas Volumes by Type (millions of Therms)	
	2025	2024
Transportation	2,463	2,434
System supply	687	698
Total	3,150	3,132

Regulatory Environments

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

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

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

Other Electric Utilities

For the millions of USD (except as indicated)	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Operating revenues – regulated electric	\$ 102	\$ 107	\$ 413	\$ 413
Regulated fuel for generation and purchased power	\$ 51	\$ 55	\$ 211	\$ 215
Contribution to consolidated adjusted net income	\$ 11	\$ 15	\$ 31	\$ 35
Contribution to consolidated adjusted net income – CAD	\$ 15	\$ 21	\$ 43	\$ 48
Equity securities MTM loss	\$ (1)	\$ (1)	\$ -	\$ -
Contribution to consolidated net income	\$ 10	\$ 14	\$ 31	\$ 35
Contribution to consolidated net income – CAD	\$ 13	\$ 19	\$ 43	\$ 48
Electric sales volumes (GWh)	330	323	1,307	1,307
Electric production volumes (GWh)	345	347	1,390	1,403
Average fuel cost in dollars per MWh	\$ 148	\$ 159	\$ 152	\$ 153

The impact of the change in FX rates on CAD earnings and adjusted net income for the three months and year ended December 31, 2025 was minimal.

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

For the millions of USD	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
BLPC	\$ 7	\$ 13	\$ 19	\$ 27
GBPC	1	3	10	11
Other	3	(1)	2	(3)
Contribution to consolidated adjusted net income	\$ 11	\$ 15	\$ 31	\$ 35

Net Income

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

For the millions of USD	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Contribution to consolidated net income – 2024	\$	14	\$	35
Decreased operating revenues quarter-over-quarter due to lower fuel revenue and lower miscellaneous revenue at BLPC		(5)		-
Decreased regulated fuel for generation and purchased power due to lower fuel costs at BLPC and GBPC		4		4
Increased income tax expense year-over-year due to the 2025 remeasurement of deferred income tax liabilities as a result of a corporate income tax rate change at BLPC		1		(2)
Increased depreciation and amortization expense at GBPC due to increased generation units in service		(4)		(5)
Other		-		(1)
Contribution to consolidated net income – 2025	\$	10	\$	31

Regulatory Environments

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

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

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

Other

For the millions of dollars	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Marketing and trading margin (1)(2)	\$ 60	\$ 35	\$ 158	\$ 77
Other non-regulated operating revenue	7	10	32	32
Total operating revenues – non-regulated	\$ 67	\$ 45	\$ 190	\$ 109
Contribution to consolidated adjusted net (loss) income	\$ (74)	\$ (59)	\$ (301)	\$ (342)
MTM (loss) gain, after-tax (3)	(97)	(144)	41	(291)
Charges related to the pending sale of NMGC, after-tax (4)	-	-	(72)	(217)
Gain on sale of LIL, after-tax (5)(6)	-	22	-	129
Financing structure wind-up	-	58	-	58
Charges related to wind-down costs and certain asset impairments, after-tax (7)	-	(23)	-	(23)
Contribution to consolidated net (loss) income	\$ (171)	\$ (146)	\$ (332)	\$ (686)

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

(2) Marketing and trading margin excludes a MTM loss, pre-tax of \$144 million in Q4 2025 (2024 – \$159 million loss) and a MTM gain, pre-tax of \$16 million for the year ended December 31, 2025 (2024 – \$357 million loss).

(3) Net of income tax recovery of \$39 million for the three months ended December 31, 2025 (2024 – \$57 million recovery) and \$17 million expense for the year ended December 31, 2025 (2024 – \$117 million recovery).

(4) Includes an impairment charge of \$75 million (\$71 million after-tax) and transaction costs of \$2 million (\$1 million after-tax) for the year ended December 31, 2025, and impairment charges of \$210 million (\$198 million, after-tax) and transaction costs of \$25 million (\$19 million after-tax) for the year ended December 31, 2024.

(5) On June 4, 2024, Emera completed the sale of its LIL equity interest. For further details on the transaction, refer to note 4 in the consolidated financial statements.

(6) Includes an income tax recovery of \$22 million for the three months ended December 31, 2024 and net income tax expense of \$53 million for the year ended December 31, 2024.

(7) Primarily relates to Block Energy, net of income tax recovery of \$6 million for the year ended December 31, 2024.

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

For the millions of dollars	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Emera Energy:				
EES	\$ 33	\$ 16	\$ 80	\$ 30
Other	(1)	(2)	(6)	2
Corporate – see breakdown below	(106)	(73)	(380)	(360)
Block Energy	-	-	6	(13)
Other	-	-	(1)	(1)
Contribution to consolidated adjusted net (loss) income	\$ (74)	\$ (59)	\$ (301)	\$ (342)

Net Income (Loss)

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

For the millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net (loss) income – 2024	\$ (146)	\$ (686)
Increased marketing and trading margin at EES due to favourable weather conditions that led to higher natural gas prices and increased volatility that created profitable opportunities	25	81
Decreased equity earnings at Bear Swamp due to lower generation as a result of a prolonged unplanned outage	(3)	(17)
Increased interest expense primarily due to increased Corporate debt and the impact of a weaker CAD on USD interest expense, partially offset by lower interest rates	(4)	(14)
Decreased income tax recovery due to decreased loss before provision for income taxes and decreased deferred income tax asset valuation allowance adjustment	(31)	(26)
Decreased MTM loss, after-tax, due to a gain on Corporate FX hedges compared to a loss in prior year. Year-over-year also decreased due to changes in existing positions and lower amortization of gas transportation assets at EES	47	332
Charges related to the pending sale of NMGC, after-tax	-	145
Gain on sale of LIL, after-tax in 2024	(22)	(129)
Financing structure wind-up in 2024	(58)	(58)
Charges related to wind-down costs and certain asset impairments, after-tax in 2024	23	23
Other	(2)	17
Contribution to consolidated net (loss) income – 2025	\$ (171)	\$ (332)

Emera Energy

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

In 2025, as a result of a strong Q1, EES adjusted its annual earnings guidance range to \$35 million USD to \$45 million USD. EES' contribution to consolidated adjusted net income was \$33 million in Q4 2025, compared to \$16 million in Q4 2024; and \$80 million (\$57 million USD) for the year ended December 31, 2025, compared to \$30 million (\$21 million USD) for the same period in 2024. Market conditions in 2025 were favourable compared to 2024 due to weather conditions which led to higher natural gas prices and volatility.

MTM Adjustments

Emera Energy's "Marketing and trading margin", "Income from equity investments" and "Income tax expense (recovery)" are affected by MTM adjustments. Variance explanations of the MTM changes for this quarter and for the year are explained in the table above.

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

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

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

Corporate

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

For the millions of dollars	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Operating expenses (1)	\$ (35)	\$ (23)	\$ (78)	\$ (74)
Interest expense	(101)	(97)	(381)	(367)
Income tax recovery	48	76	160	170
Preferred dividends	(19)	(19)	(75)	(73)
Other (2)(3)	1	(10)	(6)	(16)
Corporate adjusted net loss (4)(5)(6)(7)	\$ (106)	\$ (73)	\$ (380)	\$ (360)

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

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

(3) Includes a realized net loss, pre-tax of \$4 million (\$2 million after-tax) for the three months ended December 31, 2025 (2024 – \$5 million net loss, pre-tax and \$4 million loss, after-tax) and a \$16 million net loss, pre-tax (\$11 million after-tax) for the year ended December 31, 2025 (2024 – \$12 million net loss, pre-tax and \$9 million loss after-tax) on FX hedges, as discussed above.

(4) Excludes a MTM gain, after-tax of \$5 million for the three months ended December 31, 2025 (2024 – \$25 million loss, after-tax) and a MTM gain, after-tax of \$28 million for the year ended December 31, 2025 (2024 – \$31 million loss, after-tax).

(5) Excludes a gain on sale of LIL, after-tax, of \$107 million for the year ended December 31, 2024.

(6) Excludes certain charges related to the pending sale of NMGC of \$77 million (\$72 million after-tax) for the year ended December 31, 2025 (2024 - \$235 million, pre-tax and \$217 million, after-tax).

(7) Excludes the tax recovery of \$58 million related to a specific financing structure and its wind-up and \$22 million on reversal of a prior year valuation allowance related to the sale of LIL for the three months and year ended December 31, 2024.

LIQUIDITY AND CAPITAL RESOURCES

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

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has an approximate \$20 billion capital investment plan over the 2026 through 2030 period and supports ongoing growth. Capital investments at Emera's regulated utilities are subject to regulatory approval.

Emera has sufficient liquidity to service debt obligations as they come due and to meet any near-term capital investment requirements as currently planned. Emera plans to use cash from operations, debt raised at the utilities, Corporate equity, and proceeds from the pending sale of NMGC to support normal operations, repayment of existing debt, and capital requirements. Debt raised at certain of the Company's utilities is subject to applicable regulatory approvals. Generally, Corporate equity requirements in support of the Company's capital investment plan are expected to be funded through issuance of hybrid securities and issuance of common equity through Emera's DRIP and ATM programs.

Emera has total committed credit facilities with varying maturities that cumulatively provide \$2.8 billion CAD and \$2.1 billion USD of credit, with approximately \$999 million CAD and \$1,056 million USD undrawn and available at December 31, 2025. The Company was holding a cash balance of \$355 million, which includes \$6 million classified as assets held for sale, related to the pending sale of NMGC, at December 31, 2025. For further discussion, refer to the "Debt Management" section below.

Consolidated Cash Flow Highlights

Significant changes in the Consolidated Statements of Cash Flows between the years ended December 31, 2025 and 2024 include:

millions of dollars	2025	2024	Change
Cash, cash equivalents, restricted cash, and cash associated with assets held for sale, beginning of period	\$ 221	\$ 588	\$ (367)
Provided by (used in):			
Operating cash flow before changes in working capital	2,559	2,194	365
Changes in non-cash working capital	(757)	452	(1,209)
Operating activities	\$ 1,802	\$ 2,646	\$ (844)
Investing activities	(3,482)	(2,218)	(1,264)
Financing activities	1,841	(818)	2,659
Effect of exchange rate changes on cash, cash equivalents, restricted cash, and cash associated with assets held for sale	(11)	23	(34)
Cash, cash equivalents, restricted cash, and cash associated with assets held for sale, end of period	\$ 371	\$ 221	\$ 150

Cash Flow from Operating Activities

Net cash provided by operating activities decreased \$844 million to \$1,802 million for the year ended December 31, 2025, compared to \$2,646 million in 2024.

Cash from operations before changes in working capital increased \$365 million for the year ended December 31, 2025. This increase was due to higher storm cost recoveries at TEC, new base rates at TEC and NMGC, and higher marketing and trading margin at EES. These were partially offset by proceeds from the FAM asset sale at NSPI in Q2 2024 and higher fuel under-recoveries at TEC.

Changes in working capital decreased operating cash flows by \$1,209 million for the year ended December 31, 2025. This decrease was due to unfavourable changes in accounts payable at TEC reflecting the timing and payment of storm invoices, unfavourable changes in accounts receivable at TEC due to increased base rates and storm cost recoveries, and unfavourable changes in accounts receivable and fuel inventory at NSPI. These were partially offset by favourable changes in accounts receivable at PGS.

Cash Flow Used in Investing Activities

Net cash used in investing activities increased \$1,264 million to \$3,482 million for the year ended December 31, 2025, compared to \$2,218 million in 2024. The increase was due to the proceeds of \$927 million received in 2024 on the sale of LIL and higher capital investment, partially offset by proceeds on the disposal of assets.

Capital expenditures for the year ended December 31, 2025, including AFUDC, were \$3,594 million compared to \$3,206 million in 2024. Details of capital spending by segment are shown below:

- \$2,221 million – Florida Electric Utility (2024 – \$1,998 million);
- \$648 million – Canadian Electric Utilities (2024 – \$494 million);
- \$624 million – Gas Utilities and Infrastructure (2024 – \$626 million);
- \$95 million – Other Electric Utilities (2024 – \$81 million); and
- \$6 million – Other (2024 – \$7 million).

Cash Flow from Financing Activities

Net cash provided by financing activities increased \$2,659 million to \$1,841 million for the year ended December 31, 2025, compared to net cash used in financing activities of \$818 million in 2024. The increase was due to higher net borrowings on committed credit facilities at NSPI and TEC, higher proceeds from Corporate debt, proceeds from short-term debt issuances at NSPI and NMGC, retirement of long-term debt at TEC and NMGC in 2024 and higher proceeds from long-term debt at TEC. These were partially offset by lower proceeds from long-term debt at PGS, lower issuance of common stock, and retirement of long-term debt at NSPI.

Working Capital

As at December 31, 2025, Emera's cash and cash equivalents were \$349 million (2024 – \$196 million) and Emera's investment in non-cash working capital was \$926 million (2024 – \$224 million). Of the cash and cash equivalents held at December 31, 2025, \$279 million was held by Emera's foreign subsidiaries (2024 – \$185 million). A portion of these funds are invested in countries that have certain exchange controls, approvals, and processes for repatriation. Such funds are available to fund local operating and capital requirements unless repatriated.

Contractual Obligations

As at December 31, 2025, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Long-term debt principal (1)(2)	\$ 1,297	\$ 321	\$ 763	\$ 1,824	\$ 554	\$ 15,702	\$ 20,461
Interest payment obligations (3)(4)	971	933	925	851	800	14,718	19,198
Purchased power (5)	413	422	411	459	451	5,941	8,097
Transportation (6)(7)	780	588	478	413	370	2,954	5,583
Fuel, gas supply and storage (8)	674	239	159	156	38	59	1,325
Pension and post-retirement obligations (9)	27	28	27	27	24	242	375
Asset retirement obligations	7	1	2	1	1	449	461
Capital projects	288	68	32	6	1	-	395
Other	144	69	53	49	42	294	651
	\$ 4,601	\$ 2,669	\$ 2,850	\$ 3,786	\$ 2,281	\$ 40,359	\$ 56,546

As detailed below, contractual obligations at December 31, 2025 includes those related to NMGC. On completion of the sale of NMGC, all remaining future contractual obligations will be transferred to the buyer. For further details on the pending transaction, refer to the "Other Developments" section.

(1) Includes \$663 million related to NMGC (2026: \$96 million, and \$567 million thereafter).

(2) The Company's \$1.2 billion USD, \$750 million USD and \$500 million USD hybrid notes mature in 2076, 2056 and 2054, respectively, and these maturity dates have been used in the computation of the Company's long-term debt principal and interest payment obligations at December 31, 2025. The Company has the option to repay such notes in advance of maturity upon exercise of the Company's redemption rights in accordance with the terms of the applicable indenture. Emera's \$1.2 billion USD hybrid notes are redeemable, at Emera's option, in June 2026.

(3) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2025, including any expected required payment under associated swap agreements.

(4) Includes \$311 million related to NMGC (2026: \$25 million, 2027: \$22 million, 2028: \$22 million, 2029: \$22 million, 2030: \$22 million, and \$198 million thereafter).

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

(6) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of \$121 million related to a gas transportation contract between PGS and SeaCoast through 2040.

(7) Includes \$61 million related to NMGC (2026: \$23 million, 2027: \$15 million, 2028: \$12 million, 2029: \$3 million, 2030: \$3 million and \$5 million thereafter).

(8) Includes \$101 million related to NMGC (2026: \$86 million, 2027: \$12 million and, 2028: \$3 million).

(9) Includes the estimated contractual obligation, which is calculated as the current legislatively required contributions to the registered funded pension plans, plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.

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. On December 23, 2025, NSPML received an interim order from the NSEB to collect up to \$199 million from NSPI for the recovery of costs associated with the Maritime Link in 2026, subject to a monthly holdback of up to \$4 million. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to NSEB approval.

Emera has committed to obtain certain transmission rights in New Brunswick during summer periods (April through October, inclusive) for NLH's use, if requested, effective August 15, 2021 and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Other" in the above table.

Forecasted Consolidated Capital Investments

The 2026 forecasted consolidated capital investments, including AFUDC, are as follows:

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Total
Generation	\$ 1,068	\$ 183	\$ -	\$ 56	\$ -	\$ 1,307
New renewable generation	-	-	-	7	-	7
Electric transmission (1)	321	287	-	32	-	640
Electric distribution	767	195	-	35	-	997
Gas transmission and distribution	-	-	665	-	-	665
Facilities, equipment, vehicles, and other	274	95	5	20	10	404
	\$ 2,430	\$ 760	\$ 670	\$ 150	\$ 10	\$ 4,020

(1) Electric transmission for the Canadian Electric Utilities segment includes \$40 million related to NSPML, which is recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

Debt Management

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

millions of dollars in currency as noted below	Maturity	Credit Facilities	Utilized	Undrawn and Available
<i>In CAD:</i>				
Emera – committed revolving credit facility	June 2029	\$ 1,300	\$ 523	\$ 777
NSPI – committed revolving credit facility	June 2029	800	578	222
NSPI – non-revolving facility	May 2026	500	500	-
Emera – non-revolving facility	February 2027	200	200	-
<i>In USD:</i>				
TEC – committed revolving credit facility	November 2030	1,200	774	426
TECO Finance – committed revolving credit facility	November 2030	400	5	395
PGS – revolving facility	November 2030	250	145	105
NMGC – revolving credit facility (1)	December 2027	125	16	109
NMGC – non-revolving facility (1)	October 2026	70	70	-
Other – committed revolving credit facilities	Various	21	-	21

(1) On August 5, 2024, Emera announced an agreement to sell NMGC. As a result, NMGC's assets and liabilities were classified as held for sale beginning in Q3 2024. For further details on the pending transaction, refer to the "Other Developments" section.

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly, and the Company is in compliance with covenant requirements as at December 31, 2025. Emera's significant covenant is listed below:

	Financial Covenant	Requirement	As at December 31, 2025
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.53 : 1

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

Florida Electric Utility

On November 20, 2025, TEC amended and restated its \$800 million USD committed revolving credit facility to extend the maturity date from December 1, 2028, to November 20, 2030 and increased the amount to \$1.2 billion USD. There were no other material changes in commercial terms from the prior agreement.

On March 6, 2025, TEC issued \$600 million USD of senior unsecured notes that bear interest at 5.15 per cent with a maturity date of March 1, 2035. Proceeds from this issuance were used for the repayment of a portion of TEC's outstanding commercial paper.

Canadian Electric Utilities

On May 21, 2025, NSPI entered into a \$500 million non-revolving facility which matures on May 21, 2026. The credit agreement contains customary representations and warranties, events of default and financial and other covenants. The non-revolving facility's interest rates are referenced to the Term CORRA or prime rate, plus a margin. Proceeds from this facility were used for general corporate purposes.

Gas Utilities and Infrastructure

On November 20, 2025, PGS amended and restated its \$250 million USD unsecured committed revolving credit facility to extend the maturity date from December 1, 2028, to November 20, 2030. There were no other changes in commercial terms from the prior agreement.

On October 23, 2025, NMGC entered into a \$70 million USD, 364-day term loan agreement which matures on October 22, 2026. The credit agreement contains customary representations and warranties, events of default and financial and other covenants. The non-revolving facility's interest rates are referenced to the Term SOFR plus a margin. Proceeds from this facility were used for general corporate purposes.

On September 19, 2025, NMGC amended its \$125 million USD unsecured committed revolving credit facility to extend the maturity date from December 17, 2026, to December 17, 2027. There were no other changes in commercial terms from the prior agreement.

Other

On February 20, 2026, Emera amended its \$200 million unsecured non-revolving facility to extend the maturity date from February 20, 2026 to February 19, 2027. There were no other material changes to the terms from the prior agreement.

On November 20, 2025, TECO Finance amended and restated its \$400 million USD unsecured committed revolving credit facility to extend the maturity date from December 1, 2028, to November 20, 2030. There were no other changes in commercial terms from the prior agreement.

On September 25, 2025, EUSHI Finance, Emera US Holdings Inc. ("EUSHI") and Emera filed a shelf registration statement on Form F-10 and Form F-3 ("Registration Statement"), with the Nova Scotia Securities Commission ("NSSC") and the SEC under the US/Canada Multijurisdictional Disclosure System. The Registration Statement was filed in connection with the prospective offer and issue by EUSHI Finance of one or more series of senior and/or subordinated unsecured debt securities ("Debt Securities"), in an aggregate principal amount of up to \$3 billion USD, during the 25-month period that the short form base shelf prospectus contained in the Registration Statement ("Base Shelf Prospectus"), including any further amendments thereto, remains valid. The Debt Securities may be offered in one or more transactions, at prices, with maturities and on terms to be set forth in one or more prospectus supplements to be filed with the NSSC and the SEC at the time of any such offering.

On October 3, 2025, EUSHI Finance completed an issuance of \$750 million USD fixed-to-fixed reset rate junior subordinated notes, pursuant to the prospectus supplement dated September 29, 2025, to the Base Shelf Prospectus. The notes initially bear interest at a rate of 6.25 per cent, and will reset on April 1, 2031, and every five years thereafter, to a rate per annum equal to the five-year US treasury rate plus 2.509 per cent, subject to an interest rate floor of 6.25 per cent. The notes mature on April 1, 2056. EUSHI Finance, at its option, may redeem the notes, in whole or in part, 90 days prior to the first interest reset date, and any semi-annual interest payment date thereafter, at a redemption price equal to the principal amount, plus accrued and unpaid interest on the notes to be redeemed, in accordance with the terms of the prospectus supplement; and otherwise, at the times and the redemption prices described in the prospectus supplement. The notes are fully and unconditionally guaranteed, on a joint, several and subordinated basis, by Emera, and EUSHI. Proceeds from this issuance were used for general corporate purposes, including repayment of existing debt.

On February 20, 2025, Emera amended its \$200 million unsecured non-revolving facility to extend the maturity date from February 20, 2025 to February 20, 2026. There were no other material changes to the terms from the prior agreement.

Credit Ratings

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

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

(1) On May 27, 2025, Fitch Ratings ("Fitch") revised its outlook on Emera, TEC and PGS to stable from negative with no changes to existing ratings.

Guaranteed Debt

As of December 31, 2025, the Company had \$3.70 billion USD (2024 – \$2.95 billion USD) senior unsecured notes and junior subordinated notes (collectively referred to as the "US Notes") outstanding.

The US Notes are fully and unconditionally guaranteed, on a joint and several basis, and in the case of the fixed-to-fixed reset rate junior subordinated notes due 2054 and 2056, on a joint, several and subordinated basis, by Emera and EUSHI (in such capacity, the "Guarantor Subsidiaries"). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP. EUSHI Finance is owned indirectly by Emera through EUSHI.

Other subsidiaries of the Company do not guarantee the US Notes (such subsidiaries are referred to as the "Non-Guarantor Subsidiaries"); however, Emera has unrestricted access to the assets of consolidated entities.

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

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

Summarized Statement of Income

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

For the millions of dollars	Year ended December 31	
	2025	2024
Loss from operations	\$ (145)	\$ (279)
Net gains (1)	\$ 168	\$ 442

(1) Includes \$1,143 million (2024 – \$1,352 million) in interest and dividend income, net, from non-guarantor subsidiaries.

Summarized Balance Sheet

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

As at millions of dollars	December 31	
	2025	2024
Current assets (1)	\$ 373	\$ 391
Goodwill	5,580	5,858
Other assets (2)	5,259	6,474
Total assets (3)	\$ 11,212	\$ 12,723
Current liabilities (4)	\$ 1,587	\$ 611
Long-term liabilities (5)	11,293	13,129
Total liabilities	\$ 12,880	\$ 13,740

(1) Includes \$275 million (2024 – \$217 million) in amounts due from non-guarantor subsidiaries.

(2) Includes \$4,714 million (2024 – \$5,937 million) in amounts due from non-guarantor subsidiaries.

(3) Excludes investments in non-guarantor subsidiaries. Consolidated Emera total assets are \$44,817 million (2024 – \$42,951 million).

(4) Includes \$206 million (2024 – \$184 million) due to non-guarantor subsidiaries.

(5) Includes \$4,609 million (2024 – \$5,980 million) due to non-guarantor subsidiaries.

Outstanding Stock Data

Common Stock

	millions of shares	millions of dollars
Issued and outstanding:		
Balance, December 31, 2024	295.94	\$ 9,042
Conversion of Convertible Debentures	0.02	1
Issuance of common stock under ATM program (1)	0.19	9
Issued under the DRIP, net of discounts	4.83	293
Senior management stock options exercised and Employee Share Purchase Plan	0.78	42
Balance, December 31, 2025	301.76	\$ 9,387

(1) For the year ended December 31, 2025, a total of 187,600 common shares were issued under Emera's ATM program at an average price of \$53.58 per share for gross proceeds of \$10 million (\$9 million, net of after-tax issuance costs). As at December 31, 2025, an aggregate gross sales limit of \$600 million remained available for issuance under the ATM program.

As at February 18, 2026, the amount of issued and outstanding common shares was 303.0 million.

If all outstanding stock options were converted as at February 18, 2026, an additional 4.1 million common shares would be issued and outstanding.

ATM Equity Program

On December 5, 2025, Emera renewed its ATM Program by filing a prospectus supplement to the Company's Canadian short form base shelf prospectus with the securities regulatory authorities in each of the provinces of Canada. At the same time, Emera filed a US prospectus supplement to the Company's US base prospectus included in its US registration statement on Form F-10 with the SEC. The ATM Program 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 is expected to remain in effect until January 5, 2029.

Preferred Stock

As at February 18, 2026, Emera had the following preferred shares issued and outstanding: Series A – 6.0 million; Series C – 10.0 million; Series E – 5.0 million; Series F – 8.0 million; Series H – 12.0 million; Series J – 8.0 million, and Series L – 9.0 million. Emera's preferred shares do not have voting rights unless the Company fails to pay, in aggregate, eight quarterly dividends.

On July 9, 2025, Emera announced it would not redeem the currently outstanding Cumulative 5-Year Rate Reset Preferred Shares, Series A ("Series A Shares") or the Cumulative Floating Rate First Preferred Shares, Series B ("Series B Shares") on August 15, 2025 (the "Conversion Date").

On July 16, 2025, Emera announced a dividend rate of 4.951 per cent per annum on the Series A Shares during the five-year period commencing on August 15, 2025 and ending on (and inclusive of) August 14, 2030 (\$0.3094 per Series A Share per quarter).

During the conversion period between July 16, 2025 and July 31, 2025, the holders of Series A Shares had the right, at their option, to convert all or any of their Series A Shares, on a one-for-one basis, into Series B Shares and the holders of Series B Shares had the right, at their option, to convert all or any of their Series B Shares, on a one-for-one basis, into Series A Shares. On August 7, 2025, Emera announced, after having taken into account all shares tendered for conversion by holders of its Series A Shares and Series B Shares, as the case may be (collectively, the "Holders"), by the end of the conversion period, the Company had determined that there would be outstanding on the Conversion Date less than 1 million Series B Shares. Therefore, in accordance with certain rights, privileges, restrictions and conditions attaching to the Series A Shares and the Series B Shares, the Company advised the Holders that no Series A Shares would be converted into Series B Shares and all remaining Series B Shares would automatically be converted into Series A Shares on a one-for-one basis on the Conversion Date. On the Conversion Date, there were 6 million Series A Shares and no Series B Shares outstanding.

On January 16, 2025, Emera announced that the annual fixed dividend per share for Series F shares would be reset from \$1.0505 to \$1.4372 for the five-year period from and including February 15, 2025.

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit ("DB") pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a multi-year period. Expected cash flow for DB pension plans is \$34 million in 2026 (2025 – \$38 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

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

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

Emera’s projected contributions to defined contribution pension plans are \$53 million for 2026 (2025 – \$51 million).

Defined Benefit Pension Plan Summary

in millions of dollars

Plans by region	TECO Holdings	NSPI	Caribbean	Total
Assets as at December 31, 2025	\$ 1,025	\$ 1,637	\$ 13	\$ 2,675
Accounting obligation at December 31, 2025	\$ 926	\$ 1,349	\$ 19	\$ 2,294
Accounting expense (income) during fiscal 2025	\$ 10	\$ (13)	\$ (4)	\$ (7)

Off-Balance Sheet Arrangements

Defeasance

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2025 totalled \$200 million (2024 – \$200 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 66 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.

Guarantees and Letters of Credit

Emera has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit were not included within the Consolidated Balance Sheets as at December 31, 2025:

Emera, on behalf of Brunswick Pipeline, issued a standby letter of credit for \$22 million to secure obligations under a non-revolving loan agreement. This standby letter of credit has a one-year term, expiring on March 31, 2026, and will be renewed annually, as required.

TECO Holdings Inc. (“TECO Holdings”), 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. The counterparty has the right to require TECO Holdings to provide replacement credit support either in the form of a substitute guarantee from an affiliate with an investment grade credit rating or a letter of credit or cash deposit of \$27 million USD.

TECO Holdings issued a guarantee in connection with SeaCoast’s performance obligations under a firm service agreement, which expires December 31, 2055, subject to two extension terms at the option of the counterparty with a final expiration date of December 31, 2071. The guarantee is for a maximum potential amount of \$13 million USD if SeaCoast fails to pay or perform under the firm service agreement. The counterparty has the right to require TECO Holdings to provide replacement credit support in the form of 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 has 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 guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of \$94 million USD (2024 – \$104 million USD) with terms of varying lengths.

Brunswick Pipeline, jointly and severally with Emera, have an indemnity agreement in support of a \$40 million surety bond issued in Brunswick Pipeline's favour to the CER. The purpose of the surety bond is to satisfy Brunswick Pipeline's regulatory obligation to have funds set aside for the future abandonment of the pipeline.

The Company has standby letters of credit and surety bonds in the amount of \$271 million USD (December 31, 2024 – \$105 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, 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 2026. The amount committed as at December 31, 2025 was \$70 million (December 31, 2024 – \$58 million).

Emera has provided an indemnity to a counterparty in relation to certain future tax amounts that could arise from specific future changes in Canadian federal law, subject to certain conditions and limitations. No such changes in law have been proposed at this time. A reasonable estimate of the potential amount of future payments that could result from future claims under this indemnity cannot be calculated, but the risk of having to make any significant payments under this indemnity is considered to be remote.

DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of one to two per cent per year. On September 25, 2025, the Board approved an increase in the annual common share dividend rate to \$2.9300 from \$2.9000 per common share. The first quarterly dividend payment at the increased rate was paid on November 15, 2025.

Emera's common share dividends paid in 2025 were \$2.9075 (\$0.7250 in Q1, Q2, and Q3 and \$0.7325 in Q4) per common share and for 2024 were \$2.8775 (\$0.7175 in Q1, Q2, and Q3 and \$0.7250 in Q4) per common share. This represents a dividend payout ratio of net income of 86 per cent in 2025 (2024 – 168 per cent) and a dividend payout ratio of adjusted net income of 83 per cent in 2025 (2024 – 98 per cent).

TRANSACTIONS WITH RELATED PARTIES

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

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Consolidated Statements of Income. NSPI's expense is reported in "Regulated fuel for generation and purchased power" on the Consolidated Statements of Income, totalling \$185 million for the year ended December 31, 2025 (2024 – \$324 million recovery). NSPML is accounted for as an equity investment, and therefore corresponding earnings related to this revenue are reflected in "Income from equity investments" on the Consolidated Statements of Income. For further details, refer to the "Contractual Obligations" section.

- Natural gas transportation capacity purchases from M&NP, reported in “Operating revenue – non-regulated” on the Consolidated Statements of Income, totalled \$16 million for the year ended December 31, 2025 (2024 – \$11 million).
- On March 5, 2025, NSPI sold development assets associated with the Wasoqonatl transmission line project to WTI for consideration of \$15 million. The development assets were sold at cost with no gain or loss recognized in the Consolidated Statements of Income.

As at December 31, 2025, Emera and its associated companies had \$32 million due to related parties (December 31, 2024 – \$24 million) recorded in “Other Current Liabilities” on the Consolidated Balance Sheets.

ENTERPRISE RISK AND RISK MANAGEMENT

Emera has an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee (“ERMC”) and monitored by the Board, to ensure risks are appropriately identified, assessed, monitored and subject to appropriate controls. The Board has a Safety and Risk Committee (“SRC”) to assist the Board in carrying out its safety, risk and sustainability oversight responsibilities. The SRC’s mandate includes oversight of the Company’s Enterprise Risk Management framework, including the identification, assessment, monitoring and management of enterprise risks.

The significant business risks to Emera are described below, many of which are beyond the Company’s control, and could have a material adverse effect on Emera or its subsidiaries, or their business operations, liquidity or access to or cost of capital, financial position, prospects, reputation, and/or results of operations (herein considered a “Material Adverse Effect”). The nature of risk is such that no such list is comprehensive, and the actual effect of any of the risks discussed could be materially different from what is described below. Additionally, other risks not presently known may arise, risks not currently considered material may become material in the future, or two or more risks which are not themselves material, could together be material.

Regulatory and Political Risk

The Company’s rate-regulated utilities and certain investments are subject to complex legislative and regulatory frameworks that cover material aspects of their businesses. These frameworks influence key factors such as rates and cost structures, revenue requirements, allowed ROEs, capital structures, rate base and capital investments, and the recovery of purchased electricity and fuel costs and other costs. Regulators also review the prudence of costs and make other decisions that can impact customer rates and the reliability of service. Emera’s rate-regulated utilities must obtain regulatory approvals for material aspects of their businesses, including changing or adding rates and/or riders. Such approvals often require public hearing proceedings involving numerous stakeholders, and there is no assurance in the outcomes or impact of any regulatory process or decision.

If Emera’s rate-regulated utilities are unable to recover a material amount of costs in a timely manner, are unable to earn a return on invested capital, are disallowed the recovery of certain costs, are subject to regulatory penalties, are not permitted to make certain capital investments, or are not permitted to invest in or divest certain utility assets, it could result in a Material Adverse Effect, including valuation impairments. Regulatory lag, the time between the incurrence of costs and the granting of the rates to recover those costs by regulators, may also result in a Material Adverse Effect.

Aspects of the acquisition, ownership, operations, siting, planning, construction, and decommissioning of electric generation, storage, transmission and distribution facilities and natural gas transportation and distribution systems are also subject to regulatory processes and approvals of regulators, government departments and agencies, and other third parties. The failure to obtain, maintain, and renew such approvals or significant changes in the terms and conditions thereof could have a Material Adverse Effect.

The regulatory framework, process and regulatory decisions may also be adversely affected by changes in government, shifts in government or public policy, legislative changes, regulatory decisions, geopolitical changes, changes in the economic environment, or other factors. Government interference in the regulatory process or regulatory decisions can undermine regulatory stability, predictability, and independence. Any such changes could have a Material Adverse Effect.

Change in Law Risk

The Company is also exposed to changes in the political environment and leadership, changes in law or regulations, changes to governmental policies, trade disputes, and the imposition of tariffs, any of which may impact the Company's businesses, the markets for energy and inputs thereto, or general economic conditions, and which may result in a Material Adverse Effect. This may include initiatives regarding deregulation or restructuring of the energy industry, which may result in increased competition, and increased or unrecovered costs. State and local policies in some US jurisdictions have sought to prevent or limit the ability of utilities to provide customers with the choice to use natural gas while in other jurisdictions policies have been adopted to prevent limitations on the use of natural gas. Emerging laws and policies addressing data center development may impact load growth and the need for additional utility infrastructure.

Emera cannot predict future legislative, policy, or regulatory changes, whether caused by economic, political or other factors, or the resulting operating or compliance costs or other impacts. It may be difficult for Emera to respond in an effective and timely manner to such future legislative, policy or regulatory changes.

Environmental Legislation:

Emera is subject to extensive regulation by federal, provincial, state, regional and local authorities regarding environmental matters, primarily related to its utility operations. This includes laws, regulations and policies relating to GHG emissions, renewable energy standards, climate, air quality, water quality and usage, waste management, wastewater discharges, soil quality, aquatic and terrestrial habitats, hazardous waste, health, endangered species, and wildlife mortality.

In some jurisdictions where Emera operates, government legislation and policy have mandated timelines for the shutdown of coal-fired generating facilities, set renewable energy generation targets, and introduced carbon pricing, and emissions limits. Over time, these could potentially lead to a portion of hydrocarbon infrastructure assets being subject to additional regulation and limitations in respect of GHG emissions and operations.

Both the Government of Nova Scotia and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix and reductions in GHG emissions, as well as the goal to phase out coal-fired electricity generation by 2030. The Government of Canada has also enacted regulations imposing emissions standards on coal-fired generation that would effectively require the decommissioning of such facilities. While Nova Scotia is exempted from such regulations through 2029, there is no guarantee that such exemption will continue into the future. Failure to meet such goals by 2030 or comply with applicable legislation or regulation could result in a Material Adverse Effect.

Per- and polyfluoroalkyl substances ("PFAS") are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. The Company does not manufacture PFAS but because these contaminants are ubiquitous in products and the environment, they could impact Emera's operations. Changes in environmental laws and regulations related to PFAS could result in new costs or obligations for investigation and cleanup and change the Company's land acquisition strategy for projects such as solar generation, which could result in a Material Adverse Effect.

These and new or revised environmental laws, regulations, policies, or interpretations of those laws, regulations or policies could result in a Material Adverse Effect by, among other things, preventing or delaying the development of energy infrastructure projects, restricting the use or output of certain facilities, requiring the early retirement of certain generation facilities that could result in stranded costs, limiting the availability or use of certain fuels required for the production of electricity, requiring additional pollution control equipment, curtailing sales of natural gas to new customers which could reduce future customer growth in Emera's natural gas businesses, changing the nature and timing of capital investments, requiring significant capital investments, imposing operating or other costs associated with compliance including carbon taxes or emissions allowances, or by limiting or eliminating certain operations or rendering such operations uneconomical. Impacts could be more significant in the future as the result of new or revised laws or requirements or stricter or more expansive application of existing environmental laws, regulations and policies. Failure to recover environmental costs in a timely manner through rates may also result in a Material Adverse Effect.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, exposing Emera to legal or regulatory proceedings, disputes, civil fines, injunctive relief, criminal penalties and other sanctions, which could result in a Material Adverse Effect.

Weather Risk

A Material Adverse Effect may arise from seasonal weather variations impacting energy consumption, as well as severe weather events, changing air temperatures, wildfires and other severe weather conditions that are expected to become more frequent and intense in the future. Refer to "Climate Risk".

The temperature, seasonal variations, and other weather conditions significantly influence the availability and demand for electricity and natural gas by customers, the price of energy commodities, such as fuel used by the Company's rate regulated utilities, and the production of electricity at power generation facilities. For example, NSPI could see lower sales in winter months if temperatures are warmer than expected.

Severe weather events or conditions such as hurricanes, floods, storm surge, tornadoes, droughts, fires, extreme temperatures, snow or ice storms, and other natural disasters create a risk of physical damage to the Company's assets and a risk of extended service outages or fuel supply disruptions. For example, high winds can cause widespread damage to transmission and distribution infrastructure, solar generation, and wind-powered generation. Substantially all of the Company's fossil fueled generation assets are located at or near coastal sites and, as such, are exposed to the separate and combined effects of rising sea levels and increasing storm intensity, including storm surges and flooding.

Severe weather events or conditions could reduce revenues and require the Company to incur additional costs, such as repair and replacement costs, costs of replacement power and fuel, and increased insurance costs, impacting cash flows and resulting in the need to access additional financing sources. These could result in a Material Adverse Effect if not resolved or mitigated in a timely and efficient manner through insurance or regulatory cost recovery. This risk to transmission and distribution facilities is typically not insured and, as such, the restoration cost is generally recovered through regulatory processes, either in advance through reserves, or after the fact through the establishment of regulatory assets. Recovery is not assured, is subject to prudence review, and may be subject to delay resulting in increased debt and debt servicing costs.

Severe weather events or other catastrophic natural disasters could also result in long-term reductions in demand for electricity or natural gas or the slowing of customer growth in one or more of the Company's service territories, which could have a Material Adverse Effect. The impact of extreme weather events would be amplified if the same events affect multiple utilities in the Company's portfolio.

High winds, lack of precipitation, and accumulation of fallen dead vegetation also increase the risk of wildfires resulting from the Company's infrastructure or for which the Company may otherwise have responsibility. If found to be responsible for such a fire, the Company could suffer material costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes. If not recovered through these means, or if recovery is delayed, these could result in a Material Adverse Effect. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

The Company purchases power from third-party owned hydroelectricity sources and operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities.

Climate Risk

Physical Risk:

Changes in climate may negatively impact the Company's operations as a result of increased frequency and intensity of weather events and related physical risks, any of which could result in a Material Adverse Effect (for more information refer to "Weather Risk" and "System Operating and Maintenance Risks"). An increase in physical risk associated with climate change can also adversely impact the cost and availability of insurance, insurance deductibles and self-retention, as well as credit ratings, which could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability (refer to "Liquidity and Capital Markets Risk").

Transition Risk:

As government policy related to the environment, renewable energy, and decarbonization continues to shift in various operating jurisdictions, the Company is exposed to increased uncertainty and risk arising from policy, legal, regulatory, technology, and market changes, which could result in a Material Adverse Effect. The energy transition will require the Company to address changes to environmental policies, laws and regulations which vary widely in operating jurisdictions (refer to "Environmental Legislation"). The Company's ability to address transition risk for the long-term is impacted by this increased policy uncertainty and the need to balance stakeholder expectations for reliability and affordability of energy.

The Company will be required to manage the impacts of these ongoing changes on customer demand and rates, while maintaining and integrating intermittent renewable energy and new technologies, making investments required to meet new resiliency and security standards, and adapting the Company's infrastructure and generating capacity to meet load growth, changing customer demands, and usage patterns. The energy transition and the ability of the Company to achieve government mandated environmental requirements, will require significant capital investment, and is dependent upon many factors which are outside of the Company's direct control, including the actions of governments, regulators, independent system operators, independent power producers, interconnected utilities, Indigenous communities, and other stakeholders; the development and commercialization of new and emerging technologies; and the use of offsets. These external factors and legislative, policy, or regulatory changes may cause the pace of the energy transition (including emissions reductions and the addition of more renewable energy) to materially differ from some stakeholder expectations. Depending on the regulatory response to government legislation and regulations, the Company may be exposed to the risk of reduced recovery through rates in respect of the affected assets.

Given concerns regarding carbon-emitting generation, assets and businesses may, over time, become difficult or uneconomic to insure in commercial insurance markets. Some insurance companies have limited their exposure to coal-fired electricity generation and are evaluating the medium and long-term impacts of changes in climate which may result in less insurance capacity, more restrictive coverage and increased premiums in the future. The Company could also face litigation or regulatory action related to environmental harms from GHG emissions or failure to substantiate certain environmental claims.

The failure to effectively respond to risks associated with changes in climate could adversely affect the Company's ability to deliver safe, reliable, and cost-effective service, the Company's reputation with stakeholders, its ability to operate and grow, and the Company's access to, and cost of, capital, each of which could result in a Material Adverse Effect.

Cybersecurity Risk

Emera is exposed to potential risks related to cyberattacks, data breaches, cyber-extortion, and unauthorized access that could result in a Material Adverse Effect. The Company increasingly relies on IT systems, networks and cloud infrastructure, and third-party service providers to effectively manage and safely operate its assets. This includes controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other enterprise systems. As the Company operates critical energy infrastructure, it may be at greater risk of cyberattacks, which could include those from nation-state cyber threat actors. Major emerging and ongoing global conflicts may also elevate this risk, by increasing the sophistication, magnitude, and frequency of cyberattacks.

Cyberattacks can reach the Company's assets and information via their interfaces with third parties or the public internet and gain access to critical and non-critical infrastructures. Cyberattacks can also occur via personnel with access to critical assets or trusted networks. Methods used to attack critical assets could include generic or energy-sector-specific malware delivered via network transfer, removable media, attachments, links in e-mails or other communications, or social engineering. The methods used by attackers are continuously evolving and can be difficult to predict and detect and may become more sophisticated, frequent, severe, and difficult to stop to the extent that attackers are able to leverage evolving artificial intelligence ("AI") models or tools.

Despite security measures in place, the Company's systems, assets and information could experience security breaches that could cause system failures, disrupt energy supply and delivery, business operations, or adversely affect safety. Such breaches could compromise customer, employee-related or other information systems and could result in loss of service to customers, unavailability of critical assets, safety issues, compromise billing and customer-facing information, such as outage maps, disrupt internal control and financial and back office processes, or result in the release, loss, corruption, destruction, and/or misuse of critical, sensitive, confidential or proprietary information, intellectual property, or personal information of customers or employees. These breaches could also delay delivery or result in contamination or degradation of hydrocarbon products the Company transports, stores or distributes.

Cyberattacks or unauthorized access may cause lost revenues, costs, losses, regulatory penalties and third-party damages, all or some of which, may not be recoverable through insurance, legal, regulatory cost recovery or other processes. To the extent that Emera maintains cybersecurity insurance coverage, such coverage is subject to aggregate limits that, depending on the scope and scale of impacts to the Company, are more likely to be exhausted as a result of a sophisticated single cyberattack or if multiple events were to occur within a single policy period. There is no guarantee that the Company will be able to renew such coverage on acceptable terms in the future. Resulting costs could include, amongst others, response, recovery and remediation costs, increased protection or insurance costs, and costs arising from damages and losses incurred by third parties. This could result in a Material Adverse Effect and there is no assurance that cyberattacks or other security breaches can be adequately addressed in a timely manner.

The Company seeks to manage these risks by aligning to a common set of cybersecurity standards and policies derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework, by following program maturity objectives, through periodic security assessments, by exercising and improving cybersecurity incident readiness and response programs, by hiring third-party cybersecurity experts, and through employee communication and training. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and IT including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and the United States Department of Homeland Security. The status of key elements of the Company's cybersecurity program is reported to the SRC on a quarterly basis. The Board also oversees cybersecurity risk, which is included in a risk dashboard at each regularly scheduled Board meeting. The recruitment and retention of qualified cybersecurity talent is a global issue, and difficulties in securing such resources may adversely impact the Company's ability to address these risks.

Energy Consumption Risk

Emera's rate-regulated utilities are affected by demand for energy based on changing customer patterns due to fluctuations in a number of factors including general economic conditions, weather events, customers' focus on energy efficiency, changes in rates, and advancements in new technologies such as rooftop solar, electric vehicles, data centers, and battery storage. Government policies promoting energy efficiency, distributed generation, and new technology developments that enable those policies, have the potential to impact how electricity enters the system and how it is bought and sold. In addition, increases in distributed generation may impact demand resulting in lower load and revenues. These changes could negatively impact Emera's operations, rate base, net earnings, and cash flows and result in a Material Adverse Effect.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, with a significant 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.

Emera manages currency risks through matching US denominated debt to finance its US operations and may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. The Company may enter 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 utilities permits the recovery of prudently incurred costs, including FX.

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

Liquidity and Capital Markets Risk

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by various market analysts, including credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments 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 Adverse Effect on Emera's ability to fund its growth plan.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business, its regulatory framework and legislative environment, political interference in the regulatory process, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to impacts related to changes in climate, 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.

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, which could result in a Material Adverse Effect. 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.

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

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Markets Risk".

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

Inflation Risk:

The Company may be exposed to changes in inflation that may result in increased operating and maintenance costs, capital investment, and fuel costs compared to the revenues provided by customer rates.

Public Health Crisis Risk

An outbreak of infectious disease, a pandemic or other public health threats, or a fear of any of the foregoing, could result in a Material Adverse Effect. This could include causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital investments, capital market activities, and counterparty risk; which could result in a Material Adverse Effect.

Health and Safety

The Company's operations inherently involve risk to the health and safety of employees, contractors and members of the public. Personal injury or loss of life resulting from failure to implement or observe appropriate health and safety procedures or comply with health and safety laws and regulations could result in adverse operational, reputational, legal, regulatory, or financial impacts, any of which could have a Material Adverse Effect.

Project Development and Land Use Rights Risk

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

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

Counterparty Risk

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

There is no assurance that management strategies will be effective, and significant counterparty defaults could result in a Material Adverse Effect.

Supply Chain Risk

Emera's ability to meet customer energy requirements, respond to storm-related disruptions and execute on the capital investment program in a cost-effective and timely manner are dependent on maintaining an efficient supply chain. Domestic and global supply chain issues may delay the delivery, increase the cost, or result in shortages of certain materials, fuel, equipment and other resources that are critical to the Company's operations. These disruptions may be further exacerbated by trade restrictions, inflationary pressures, labour shortages, more frequent and severe weather events, government incentives increasing demand for clean energy projects, changes in carbon-related costs, policies and regulations, and the impact of international conflicts. In addition, the imposition of custom duties or other tariffs, or an increase in trade restrictions in the future could have a Material Adverse Effect.

Fuel Supply Disruptions:

Emera's electric and natural gas utilities are exposed to the risk of fuel supply chain disruptions, both within and outside their service territories. Fuel supply disruptions may be caused by damage to, operational issues with, terrorist or cyberattacks on, impacts of severe weather or natural disasters on, third party fuel production, storage, pipeline, and distribution facilities. A significant unanticipated fuel supply disruption could result in increased exposure to commodity price risk for Emera's regulated electric and gas utilities and Emera Energy, disruption to utility operations, and adverse reputational impacts, any of which could have a Material Adverse Effect.

Commodity Price Risk

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

Regulated Utilities:

The Company's utility fuel supply is exposed to broader global market 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, tariffs, trade sanctions or embargos.

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, any of which could result in a Material Adverse Effect.

Emera Energy Marketing and Trading:

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, imposition of tariffs, 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.

Future Employee Benefit Plan Performance and Funding Risk

Emera subsidiaries have both defined benefit and defined contribution employee pension plans that cover employees and retirees. All defined benefit plans are closed to new entrants, except for the TECO Holdings Group Retirement Plan and the Grand Bahama Power Company Limited Union Employees' Pension Plan. The cost of providing these benefit plans varies depending on plan provisions, interest rates, inflation, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, contributions to the plans and the pension and post-retirement liabilities) and expectations around future salary growth, inflation and mortality. The three largest drivers of cost are investment performance, interest rates and inflation, which are affected by global financial and capital markets. Depending on future interest rates and future inflation and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could have a Material Adverse Effect.

Labour Risk

Emera's ability to deliver service to its customers and to execute its growth plan depends on attracting, developing and retaining a skilled workforce. Utilities are faced with demographic challenges related to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop and retain an appropriately qualified workforce could have a Material Adverse Effect.

Approximately 30 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have a Material Adverse Effect.

Technology Risk

Emera relies on various technology systems to manage operations, including increasing reliance on solutions operated by third parties, such as software as a service and third-party cloud hosting. This subjects Emera to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its operations, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems. Technological reliance may increase vulnerability to cyberattacks and data breaches and increase operational reliance on technology systems and third parties. The rapid evolution of AI has the potential to disrupt existing business models and markets and could result in a Material Adverse Effect. If the Company does not successfully integrate AI in a timely and cost-effective manner, it may not fully realize anticipated efficiencies, cost savings, or service improvements. If AI systems or tools do not operate as expected, it could result in adverse operational, safety, reputational, financial, legal, privacy, data security, or other outcomes. Emera's digital transformation strategy, including investment in infrastructure modernization, emerging technologies such as Generative AI, and customer focused technologies, is driving increased investment in technology solutions, resulting in increased project risks associated with the implementation of these solutions.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the US and the Caribbean and any such changes could have a Material Adverse Effect. The value of Emera's existing deferred income tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws.

System Operating and Maintenance Risks

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, supply chain issues impacting timely access to critical equipment, activities of third parties, terrorism, cyberattacks, human error, damage to facilities, and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties, terrorism, cyberattacks, and damage to the pipeline facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect customer and public confidence, and public safety, cause damage to Company infrastructure or third-party property, and have a Material Adverse Effect.

Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all these losses, which could have a Material Adverse Effect.

Uninsured Risk

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities and to provide indemnity in the event of liability to third parties. A significant portion of Emera's electric utilities' transmission and distribution assets and its gas utilities' distribution assets are not insured, as is customary in the industry, as the cost of coverage is prohibitive. In addition, Emera accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred will be covered by insurance.

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits, or claims that fall within a significant self-insured retention could have a Material Adverse Effect, if regulatory recovery is not available.

RISK MANAGEMENT INCLUDING FINANCIAL INSTRUMENTS

The Company uses financial instruments as a method to manage its exposure to normal operating and market risks relating to commodity prices, interest rates, FX on forecast USD earnings and cash flows and forecast future cash settlements of deferred compensation obligations. In addition, the Company has contracts for the physical purchase and sale of commodities. Collectively, these contracts and financial instruments are considered derivatives.

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

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

Derivatives entered into by NSPI, NMGC and GBPC that are documented as economic hedges or for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. The change in FV of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled. Any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power or cost of natural gas are expected to be refunded to or collected from customers in future rates. TEC and PGS have no derivatives related to hedging.

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

Derivative Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars	December 31 2025	December 31 2024
<i>Regulatory Deferral:</i>		
Derivative instrument assets (1)	\$ 24	\$ 45
Derivative instrument liabilities (2)	(34)	(40)
Regulatory assets (1)	36	53
Regulatory liabilities (2)	(25)	(44)
Net asset	\$ 1	\$ 14
<i>HFT Derivatives:</i>		
Derivative instrument assets (1)	\$ 158	\$ 122
Derivatives instruments liabilities (2)	(614)	(542)
Net liability	\$ (456)	\$ (420)
<i>Other Derivatives:</i>		
Derivative instrument assets (1)	\$ 16	\$ -
Derivatives instruments liabilities (2)	(1)	(36)
Net asset (liability)	\$ 15	\$ (36)

(1) Current, other and assets held for sale.

(2) Current, long-term and liabilities associated with assets held for sale.

Realized and Unrealized Gains (Losses) Recognized in Net Income

For the millions of dollars	Year ended December 31	
	2025	2024
<i>Regulatory Deferral:</i>		
Regulated fuel for generation and purchased power (1)	\$ (14)	\$ (44)
<i>HFT Derivatives:</i>		
Non-regulated operating revenues	\$ 467	\$ 207
<i>Other Derivatives:</i>		
OM&G	\$ 41	\$ 14
Other income, net	23	(56)
Net gains (losses)	\$ 64	\$ (42)
Total net gains	\$ 517	\$ 121

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

As of December 31, 2025, the unrealized gain in AOCI was \$10 million, after-tax (December 31, 2024 – \$12 million, after-tax). For the year ended December 31, 2025, unrealized gains of \$2 million (December 31, 2024 – \$2 million) were reclassified into interest expense.

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures (“DC&P”) and internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”). The Company’s internal control framework is based on criteria published in the Internal Control Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations (“COSO”) of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company’s DC&P and ICFR as at December 31, 2025 to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Management recognizes the inherent limitations in internal control systems, no matter how well designed. Control systems determined to be appropriately designed can only provide reasonable assurance with respect to the reliability of financial reporting and may not prevent or detect all misstatements.

Change in ICFR

In April 2025, the Company experienced a Cybersecurity Incident that impacted certain financial systems and processes at its Canadian affiliates. As a result, the Company transitioned these to business continuity processes and implemented additional ICFR during this period. This transition to business continuity processes resulted in a material change in the Company’s ICFR at Canadian affiliates during the quarter ended June 30, 2025. Since this time, the Company has restored certain financial systems and transitioned back from corresponding business continuity processes, which resulted in a material change in the Company’s ICFR at its Canadian affiliates during the second half of 2025. For more information on the Cybersecurity Incident, refer to the “Other Developments” section.

There were no other changes in the Company’s ICFR, during the year ended December 31, 2025, that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations (“ARO”), and valuation of financial instruments. Management evaluates the Company’s estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise.

Rate Regulation

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

As at December 31, 2025, the Company had recorded \$3,198 million (2024 – \$3,427 million) of regulatory assets and \$1,669 million (2024 – \$1,880 million) of regulatory liabilities.

Accumulated Reserve – Cost of Removal

TEC, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO COR represents estimated funds received from customers through depreciation rates to cover future COR of PP&E upon retirement that are not legally required. The companies accrue for COR over the life of the related assets based on depreciation studies approved by their respective regulators. Costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. As at December 31, 2025, the balance of the accumulated reserve – COR within regulatory liabilities was \$729 million (2024 – \$733 million).

Pension and Other Post-Retirement Employee Benefits

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

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

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

The Company's accounting policy is to amortize the net actuarial gain or loss that exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period, or over expected average remaining lifetime of inactive members, depending on the makeup of Plan memberships. For the largest plans this is currently 16.4 years (8.0 years for 2025 benefit cost) for Canadian plans and a weighted average of 11.5 years for US plans. The Company's use of smoothed asset values reduces volatility related to amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

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

	2025		2024	
	Discount rate for benefit cost purposes	Expected return on plan assets	Discount rate for benefit cost purposes	Expected return on plan assets
TECO Holdings Group Retirement Plan	5.66%	7.05%	5.27%	7.05%
TECO Holdings Group Supplemental Executive Retirement Plan (1)	5.41%	N/A	5.15%	N/A
TECO Holdings Group Benefit Restoration Plan (1)	5.55%	N/A	5.18%	N/A
TECO Holdings Post-retirement Health and Welfare Plan	5.69%	N/A	5.28%	N/A
NMGC Retiree Medical Plan	5.67%	4.25%	5.28%	4.25%
NSPI	4.63%, 4.72%	6.00%	4.63%, 4.62%	6.00%
GBPC Salaried	5.75%	6.00%	5.75%	6.00%
GBPC Union	5.75%	5.35%	5.75%	5.35%

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

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was \$51 million in 2025 (2024 – \$56 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2025 benefit cost of \$0.5 million and \$2.0 million, respectively (2024 – \$0.5 million and \$3.0 million).

Unbilled Revenue

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for other Emera utilities. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of estimates included in determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2025, unbilled revenues totalled \$400 million (2024 – \$342 million) on total regulated operating revenues of \$8,571 million (2024 – \$7,447 million).

PP&E

PP&E represents 61 per cent of total assets on the Company's consolidated balance sheet and includes generation, transmission and distribution, and other assets of the Company.

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

Depreciation expense was \$1,259 million for the year ended December 31, 2025 (2024 – \$1,135 million).

Goodwill Impairment Assessments

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated FV of identifiable assets acquired, and liabilities assumed at the acquisition date.

Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. Application of the goodwill impairment test requires management judgment on significant assumptions and estimates. When assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

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

As of December 31, 2025, Emera's goodwill represents the excess of the acquisition purchase price for the TEC and PGS reporting units over the FV assigned to identifiable assets acquired and liabilities assumed. In Q3 2024, Emera entered into an agreement to sell NMGC. As a result, a quantitative goodwill impairment assessment was performed on the NMGC reporting unit at that time and the Company recorded a goodwill impairment charge of \$210 million (\$198 million, after-tax) or \$155 million USD (\$146 million USD, after-tax) in Q3 2024. The reduced NMGC goodwill balance of \$289 million is included in the NMGC disposal unit classified as held for sale. For further details, refer to note 23 in the consolidated financial statements.

In Q4 2025, a qualitative assessment was performed for PGS and TEC, given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2024 and Q4 2023, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their carrying amounts, including goodwill. As such, no quantitative testing was required.

As of December 31, 2025, the Company had goodwill with a total carrying amount of \$5,580 million (2024 – \$5,858 million). The change in the carrying value of goodwill from 2024 to 2025 was a result of the effect of the FX translation of Emera's foreign affiliates.

Long-Lived Assets Impairment Assessments

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

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

In 2025, impairment charges of \$75 million (\$71 million after-tax) were recognized related to the NMGC disposal group classified as held for sale and were recorded in "Impairment charges" on the Consolidated Income Statement. In 2024, impairment charges of \$19 million (\$14 million after-tax) were recognized on certain assets, \$8 million of which was included in "Other income, net" with \$11 million included in "Impairment charges" on the Consolidated Statements of Income.

Income Taxes

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

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

Asset Retirement Obligations

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

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

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

As at December 31, 2025, AROs recorded on the balance sheet were \$228 million (2024 – \$217 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately \$474 million (2024 – \$453 million), which will be incurred between 2026 and 2061. The majority of these costs will be incurred between 2035 and 2051.

Financial Instruments

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

Level Determinations and Classifications

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

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policy that is applicable to, and adopted by the Company in 2025, is described as follows:

Improvements to Income Tax Disclosures

The Company adopted Accounting Standard Update (“ASU”) 2023-09, Income Taxes (Topic 740), Improvements to Income Tax Disclosures, effective December 31, 2025. The standard enhances the transparency, decision usefulness and effectiveness of income tax disclosures by requiring consistent categories and greater disaggregation of information in the reconciliation of income taxes computed using the enacted statutory income tax rate to the actual income tax provision and effective income tax rate, as well as the disaggregation of income taxes paid (refunded) by jurisdiction. Adoption of the standard resulted in additional disclosures provided in note 11 and note 31 of Emera’s consolidated financial statements.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board (“FASB”). The following updates have been issued by the FASB but, as allowed, have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or to have an insignificant impact on the consolidated financial statements.

Accounting for Government Grants Received by Business Entities

In December 2025, the FASB issued ASU 2025-10, Government Grants (Topic 832) – Accounting for Government Grants Received by Business Entities. The ASU adds guidance to ASC 832 on the recognition, measurement, and presentation of government grants. The guidance will be effective for annual reporting periods beginning after December 15, 2028, and interim reporting periods within those annual reporting periods. Early adoption is permitted. The standard updates are to be applied using either a modified prospective, modified retrospective, or full retrospective approach, as detailed in the ASU. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements.

Targeted Improvements to the Accounting for Internal-Use Software

In September 2025, the FASB issued ASU 2025-06, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software. The standard update modernizes accounting for internal-use software by eliminating references to project stages and clarifying the threshold to begin capitalizing costs. The standard update also specifies that the disclosure requirements under ASC 360, Property, Plant and Equipment, apply to capitalized software costs accounted under ASC 350-40. The guidance will be effective for annual reporting periods beginning after December 15, 2027, and interim reporting periods within those annual reporting periods. Early adoption is permitted. The standard updates are to be applied using either a prospective, retrospective, or modified transition approach. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03, Income Statement Reporting – Comprehensive Income – Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. The standard update improves the disclosures about a public business entity’s expenses by requiring more detailed information about the types of expenses (including purchases of inventory, employee compensation, depreciation and amortization) included within income statement expense captions. The guidance will be effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The standard updates are to be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact of adoption of the standard update on its consolidated financial statements disclosures.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended

millions of dollars (except per share amounts)	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024
Operating revenues	\$ 2,006	\$ 2,106	\$ 1,988	\$ 2,676	\$ 1,763	\$ 1,802	\$ 1,617	\$ 2,018
Net income attributable to common shareholders	\$ 68	\$ 228	\$ 135	\$ 583	\$ 154	\$ 4	\$ 129	\$ 207
EPS – basic	\$ 0.23	\$ 0.76	\$ 0.45	\$ 1.96	\$ 0.52	\$ 0.01	\$ 0.45	\$ 0.73
EPS – diluted	\$ 0.25	\$ 0.76	\$ 0.45	\$ 1.96	\$ 0.52	\$ 0.01	\$ 0.45	\$ 0.73

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

Q4 2025 compared to Q4 2024

For explanation of variances, refer to the “Consolidated Income Statement Highlights” section.

Q3 2025 compared to Q3 2024

For Q3 2025, net income attributable to common shareholders, compared to Q3 2024, increased \$224 million primarily due to charges related to the pending sale of NMGC recognized in Q3 2024; and increased earnings at TEC. These were partially offset by increased MTM losses; lower earnings at NSPI and NMGC; and higher Corporate costs. The change in EPS was also impacted by an increase in weighted average shares outstanding.

Q2 2025 compared to Q2 2024

Q2 2025 net income attributable to common shareholders increased by \$6 million primarily due to decreased MTM losses; increased earnings at TEC, EES, and NMGC; higher Corporate income tax recovery; and decreased Corporate OM&G. These were partially offset by the gain on sale of LIL recognized in Q2 2024; charges related to the pending sale of NMGC recognized in Q2 2025; lower earnings at NSPI; decreased equity earnings from LIL; and increased Corporate interest expense. Q2 2025 EPS – basic and diluted were consistent with Q2 2024.

Q1 2025 compared to Q1 2024

Q1 2025 net income attributable to common shareholders increased by \$376 million and EPS – basic and diluted increased by \$1.23 compared to Q1 2024. The increases were primarily due to decreased MTM losses; increased earnings at TEC, NSPI, EES and NMGC; the impact of a weaker CAD; and decreased Corporate OM&G. These changes were partially offset by decreased income from equity investments due to the sale of LIL. The change in EPS was also impacted by an increase in weighted average shares outstanding.