

Financial Statements
Nova Scotia Power Inc.

Regulated Statements of Income

For the		Three months ended				Year ended	
millions of Canadian dollars		December 31				December 31	
	<i>Actual</i>		<i>Test Year</i>	<i>Prior Year</i>	<i>Actual</i>	<i>Test Year</i>	<i>Prior Year</i>
	<i>2025</i>		<i>2024</i>	<i>2024</i>	<i>2025</i>	<i>2024</i>	<i>2024</i>
Operating revenues	\$ 504		\$ 468	\$ 478	\$ 1,943	\$ 1,795	\$ 1,854
Operating expenses							
Fuel for generation and purchased power	269		242	(216)	1,065	941	509
Fuel adjustment mechanism	(36)		(21)	436	(161)	(88)	350
Demand side management cost recovery rider	-		-	-	(1)	-	(1)
Storm cost recovery rider	6		-	-	24	-	-
Settlement agreement adjustment	-		(9)	-	-	(36)	(1)
Operating, maintenance and general	97		75	85	342	298	328
Demand side management	16		15	15	63	58	58
Provincial grants and taxes	12		11	12	49	44	48
Depreciation and amortization	76		74	72	296	287	280
Total operating expenses	440		387	404	1,677	1,504	1,571
Income from operations	64		81	74	266	291	283
Other income, net	(8)		(9)	(7)	(33)	(41)	(28)
Interest expense, net	43		33	41	170	130	164
Income before provision for income taxes	29		57	40	129	202	147
Income tax (recovery) expense	(3)		-	(39)	(36)	-	(33)
Net income	\$ 32		\$ 57	\$ 79	\$ 165	\$ 202	\$ 180

Regulated Balance Sheets

As at millions of Canadian dollars	December 31 2025	December 31 2024
Assets		
Current assets		
Receivables, net	\$ 557	\$ 417
Due from related parties	131	86
Inventory	299	295
Derivative instruments	15	28
Regulatory assets	45	67
Prepaid expenses	21	24
Total current assets	1,068	917
Property, plant and equipment, net of accumulated depreciation	5,302	4,908
Other assets		
Income taxes receivable	127	87
Derivative instruments	9	16
Pension and post-retirement assets	353	185
Regulatory assets	1,221	974
Other long-term assets	40	49
Total other assets	1,750	1,311
Total assets	\$ 8,120	\$ 7,136

	December 31 2025	December 31 2024
Liabilities and Equity		
Current liabilities		
Bank indebtedness	\$ 42	\$ 2
Short-term debt	500	-
Current portion of long-term debt	40	125
Accounts payable	300	197
Income taxes payable	-	3
Derivative instruments	19	25
Regulatory liabilities	17	29
Pension and post-retirement liabilities	7	8
Other current liabilities	120	142
Total current liabilities	1,045	531
Long-term liabilities		
Long-term debt	3,615	3,217
Deferred income taxes	1,057	899
Derivative instruments	7	13
Regulatory liabilities	8	71
Asset retirement obligations	144	137
Pension and post-retirement liabilities	66	67
Redeemable preferred shares	10	10
Other long-term liabilities	67	51
Total long-term liabilities	4,974	4,465
Equity		
Common stock	1,057	1,406
Accumulated other comprehensive loss	137	(8)
Retained earnings	907	742
Total equity	2,101	2,140
Total liabilities and equity	\$ 8,120	\$ 7,136

Regulated Operating Revenues

For the millions of Canadian dollars		Three months ended December 31			Year ended December 31	
	<i>Actual</i> 2025	<i>Test Year</i> 2024	<i>Prior Year</i> 2024	<i>Actual</i> 2025	<i>Test Year</i> 2024	<i>Prior Year</i> 2024
Electric Revenues						
Residential	\$ 285	\$ 246	\$ 260	1,073	\$ 928	\$ 997
Commercial						
Small General	17	15	17	74	61	68
General	103	98	98	396	381	379
Large General	12	14	13	52	58	52
Total Commercial	132	127	128	522	500	499
Industrial						
Small Industrial	11	11	10	43	43	41
Medium Industrial	18	18	19	72	69	72
Large Industrial	20	24	21	82	94	83
ELIADC/Load Retention and Other Industrial	18	25	19	73	97	80
Total Industrial	67	78	69	270	303	276
Other						
Municipal	4	1	4	19	6	18
Unmetered	1	5	5	3	20	20
Wholesale Market	6	2	1	21	5	3
Total Other	11	8	10	43	31	41
Total In-Province Electric Revenues	495	459	467	1,908	1,762	1,813
Export Revenues	-	-	-	-	-	-
Total Electric Revenues	495	459	467	1,908	1,762	1,813
Other Operating Revenues	9	9	11	35	33	41
Total Operating Revenues	\$ 504	\$ 468	\$ 478	\$ 1,943	\$ 1,795	\$ 1,854

Regulated Operating, Maintenance and General

For the millions of Canadian dollars	<i>Actual</i> 2025		Three months ended December 31				Year ended December 31	
			<i>Test Year</i> 2024 ⁽¹⁾	<i>Prior Year</i> 2024	<i>Actual</i> 2025		<i>Test Year</i> 2024	<i>Prior Year</i> 2024
Power Production	\$ 25		\$ 25	\$ 25	\$ 111 ²		\$ 99	\$ 102
Enterprise Asset Management and Project Implementation	2		3	1	9 ³		10	8
Environment	1		1	1	3		3	3
Customer Operations	35		24	30	143 ⁴		99	129
Customer Service	9		7	9	29 ⁵		26	29
Corporate Groups	29		23	25	111 ⁶		95	108
Corporate Adjustments	(5)		(11)	(7)	(69) ⁷		(46)	(56)
Pension	1		3	1	5 ⁸		12	5
Total Operating Maintenance and General	\$ 97		\$ 75	\$ 85	\$ 342		\$ 298	\$ 328

Notes:

1. Quarterly test year figures are based on an allocation of the annual test year amounts as these amounts are not profiled quarterly.
2. Increased compared to test year primarily due to increased thermal plant, partially offset by decreased costs in renewables.
3. Decrease compared to test year primarily due to decreased operational costs for generation asset management and project costs.
4. Increased compared to test year due to increased operational costs for lines services, utility services, fleet and inspection services.
5. Increased compared to test year primarily due to increased operating costs in the Customer Care group.
6. Increased compared to test year primarily due to increased operating costs for information technology and human resources.
7. Decreased compared to test year primarily due to increased administrative overhead credits as a result of the capital program.
8. Decreased compared to test year due to changes in actuarial assumptions.

Summary of Unregulated Adjustments

As at	December 31
millions of Canadian dollars	2025
Unregulated Retained Earnings	
Unregulated retained earnings - December 31, 2024	\$200.8
Unregulated compensation (including director share units/performance share units and management incentive)	16.3
Interest expense, unregulated assets	2.0
Depreciation expense, unregulated assets	2.0
Donations and sponsorships	1.5
Fuel adjustment mechanism disallowance	1.1
Performance standards penalty	1.0
Other	0.1
Unregulated rental income from Lower Water Street	(0.7)
Extended customer credit monitoring service costs and manual meter reading costs	7.9
Income taxes, unregulated adjustments	(8.9)
Lingan U2 disallowed operating costs	1.4
Subtotal	23.7
Unregulated retained earnings - December 31, 2025	\$224.5
Unregulated Property, Plant and Equipment	
Unregulated Portion of Maritime Link Project	\$34.8
Unapproved Authorization to Overspend	30.4
Unregulated Portion of Lower Water Street	8.2
Burnside Natural Gas Conversion Project	2.8
Kentville Electric Purchase Price Discrepancy Goodwill	2.3
Unregulated Portion of Tufts Cove 6 Project	1.4
Unregulated Land	1.0
Electric Vehicle Charging Station Project, net of government contributions	2.7
Total unregulated property, plant and equipment	\$83.6
Unregulated Other Assets	
Deferred General Rate Application costs	\$1.3
Deferred Securitization and Nova Scotia Independent Energy System Operator costs	0.7
Sponsorship	0.6
Total unregulated other assets	\$2.6
Investments Subject to Significant Influence	
Wasoqonatl Transmission Incorporated ("WTI") investment	\$8.6
Total investment subject to significant influence	\$8.6
Unregulated Income Taxes	
Current income taxes receivable (payable)	(\$1.1)
Total current income taxes receivable (payable)	(\$1.1)
Unregulated Deferred Income Taxes	
Increase to long-term deferred income taxes liability related to unregulated expenditures	\$198.5
Total unregulated deferred income taxes	\$198.5
Unregulated Due to Related Parties	
Due to Emera related to Part VI.1 Tax	(\$168.7)
Total unregulated due to related parties	(\$168.7)
Common Stock	
Equity issuance related to investment in WTI	(\$8.6)
Equity issuance classified as regulated repayment of Due From Related Parties	(\$192.0)
Total Common Stock	(\$200.6)
Unregulated Due from Related Parties	
Effect of unregulated adjustments	\$147.4
Effect of unregulated adjustments	\$147.4

Nova Scotia Power Inc.

Regulated Return on Equity

As at	December 31	
millions of Canadian dollars	2025	
	Regulated Equity	Regulated Capitalization
December 31, 2024	\$2,147.6	\$5,391.0
March 31, 2025	1,918.5	5,526.7
June 30, 2025	1,931.2	5,709.6
September 30, 2025	1,940.4	5,788.7
December 31, 2025	1,963.5	6,015.2
Total	\$9,901.1	\$28,431.3
Five Quarter Average	\$1,980.2	\$5,686.3
Five Quarter Average Regulated Common Equity	34.8%	
Regulated Net Earnings - December 31, 2025	\$164.6	
Regulated Return on Equity (Regulated Net Earnings / Average Regulated Common Equity)	8.31%	

NOVA SCOTIA POWER INC.

Consolidated Financial Statements

December 31, 2025 and 2024

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Nova Scotia Power Inc. ("NSPI" or "the Company") and the information in the Management's Discussion & Analysis ("MD&A") are the responsibility of management and have been approved by the Board of Directors ("Board").

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

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

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements.

The Board meets periodically with management, internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the MD&A, the consolidated financial statements and the external auditors' report. The Board also considers, for review and approval by the shareholders, the appointment of the external auditors.

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

February 23, 2026

"Peter Gregg"
President and Chief Executive Officer

"Jared Green"
Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of Nova Scotia Power Inc.

Opinion

We have audited the consolidated financial statements of Nova Scotia Power Inc. and its subsidiary (the "Company"), which comprise the consolidated balance sheets as at December 31, 2025 and 2024, and the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2025 and 2024, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

Basis for opinion

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

Other information

Management is responsible for the other information. The other information comprises Management's Discussion and Analysis.

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

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

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

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

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

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

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

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

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

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

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

- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the consolidated financial statements. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

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

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

Ernst & Young LLP
Chartered Professional Accountants

Halifax, Canada
February 23, 2026

Nova Scotia Power Inc.
Consolidated Statements of Income

For the millions of dollars	Year ended December 31	
	2025	2024
Operating revenues (note 4)	\$ 1,944	\$ 1,855
Operating expenses		
Fuel for generation and purchased power	1,065	509
Fuel adjustment mechanism ("FAM") and other deferrals (note 5)	(137)	350
Operating, maintenance and general ("OM&G")	370	350
Demand-side management ("DSM")	63	58
Provincial grants and taxes	49	48
Depreciation and amortization	298	282
Total operating expenses	1,708	1,597
Income from operations	236	258
Other income, net	(32)	(28)
Interest expense, net (note 6)	172	168
Income before provision for income taxes	96	118
Income tax recovery (note 7)	(45)	(42)
Net income	\$ 141	\$ 160

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

Nova Scotia Power Inc.
Consolidated Statements of Comprehensive Income

For the millions of dollars	Year ended December 31	
	2025	2024
Net income	\$ 141	\$ 160
Other comprehensive income		
Net change in unrecognized pension and post-retirement costs (note 8)	145	70
Comprehensive income	\$ 286	\$ 230

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

**Nova Scotia Power Inc.
Consolidated Balance Sheets**

As at millions of dollars	December 31 2025	December 31 2024
Assets		
Current assets		
Receivables, net (note 9)	\$ 557	\$ 417
Inventory (note 10)	299	295
Derivative instruments (notes 11 and 12)	15	28
Regulatory assets (note 5)	45	67
Prepaid expenses	21	24
Total current assets	937	831
Property, plant and equipment , net of accumulated depreciation of \$3,716 and \$3,499, respectively (note 13)	5,385	4,974
Other assets		
Income taxes receivable	127	87
Derivative instruments (notes 11 and 12)	9	16
Pension and post-retirement assets (note 14)	353	185
Regulatory assets (note 5)	1,221	974
Investments subject to significant influence (note 25)	9	-
Other long-term assets (note 15)	43	50
Total other assets	1,762	1,312
Total assets	\$ 8,084	\$ 7,117
Liabilities and Equity		
Current liabilities		
Bank indebtedness (note 17)	\$ 42	\$ 2
Short-term debt (note 17)	500	-
Current portion of long-term debt (note 19)	40	125
Accounts payable	300	197
Due to related parties (note 16)	16	13
Income taxes payable	1	3
Derivative instruments (notes 11 and 12)	19	25
Regulatory liabilities (note 5)	17	29
Pension and post-retirement liabilities (note 14)	7	8
Other current liabilities (note 18)	120	142
Total current liabilities	1,062	544
Long-term liabilities		
Long-term debt (note 19)	3,615	3,217
Due to related parties (note 16)	169	137
Deferred income taxes (note 7)	859	739
Derivative instruments (notes 11 and 12)	7	13
Regulatory liabilities (note 5)	8	71
Asset retirement obligations (note 20)	144	137
Pension and post-retirement liabilities (note 14)	66	67
Redeemable preferred stock (note 23)	10	10
Other long-term liabilities (note 15)	67	51
Total long-term liabilities	4,945	4,442
Equity		
Common stock, no par value, unlimited shares authorized, 173.5 million shares issued and outstanding	1,258	1,598
Accumulated other comprehensive income (loss) (note 8)	137	(8)
Retained earnings	682	541
Total equity	2,077	2,131
Total liabilities and equity	\$ 8,084	\$ 7,117

Commitments and contingencies (note 21)
The accompanying notes are an integral part
of these consolidated financial statements.

Approved on behalf of the Board of Directors
"Scott Balfour" *"Peter Gregg"*
Chair of the Board **President and Chief Executive Officer**

Nova Scotia Power Inc.
Consolidated Statements of Cash Flows

For the millions of dollars	Year ended December 31	
	2025	2024
Operating activities		
Net income	\$ 141	\$ 160
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	300	283
Allowance for equity funds used during construction	(9)	(7)
Deferred income taxes, net	(39)	(41)
Net change in pension and post-retirement obligations	(25)	(26)
FAM	(158)	451
Other operating activities, net	83	11
Changes in non-cash working capital:		
Receivables, net	(140)	13
Income taxes receivable	(40)	(5)
Inventory	(4)	50
Prepaid expenses	3	1
Accounts payable	29	17
Due to/from related parties	3	-
Income taxes payable	(2)	2
Other current liabilities	(24)	10
Net cash provided by operating activities	118	919
Investing activities		
Additions to property, plant and equipment	(604)	(447)
Allowance for borrowed funds used during construction	(8)	(6)
Removal of assets from service, net of salvage	(27)	(34)
Proceeds from sale of assets	17	2
Other investing activities	(9)	2
Net cash used in investing activities	(631)	(483)
Financing activities		
Change in bank indebtedness	40	2
Issuance of short-term debt	500	-
Retirement of long-term debt	(125)	-
Proceeds from long-term debt	55	19
Net borrowings (repayments) under committed credit facility	383	(544)
Return of capital	(340)	-
Issuance of common stock	-	1
Other financing activities	-	8
Net cash provided by (used in) financing activities	513	(514)
Net change in cash	-	(78)
Cash, beginning of period	-	78
Cash, end of period	\$ -	\$ -
Supplemental disclosure of cash paid:		
Interest	\$ 177	\$ 196
Federal income taxes, net of refunds (1)	\$ 32	\$ 27
Supplemental disclosure of non-cash activity:		
Increase (decrease) in accrued capital expenditures	\$ 74	\$ (3)

(1) Income taxes paid includes \$32 million (2024 - \$28 million) of Part VI. 1 tax that is transferred from, and fully funded by, Emera Incorporated ("Emera").

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

Nova Scotia Power Inc.

Consolidated Statements of Changes in Equity

millions of dollars	Common Stock	AOCI (AOCL) (1)	Retained Earnings	Total Equity
Balance, December 31, 2024	\$ 1,598	\$ (8)	\$ 541	\$ 2,131
Net income	-	-	141	141
Other comprehensive income	-	145	-	145
Return of capital	(340)	-	-	(340)
Balance, December 31, 2025	\$ 1,258	\$ 137	\$ 682	\$ 2,077
Balance, December 31, 2023	\$ 1,597	\$ (78)	\$ 381	\$ 1,900
Net income	-	-	160	160
Other comprehensive income	-	70	-	70
Issuance of common stock	1	-	-	1
Balance, December 31, 2024	\$ 1,598	\$ (8)	\$ 541	\$ 2,131

(1) Accumulated other comprehensive income (loss) ("AOCI")/("AOCL")

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

**Nova Scotia Power Inc.
Notes to the Consolidated Financial Statements**

As at December 31, 2025 and 2024

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Nova Scotia Power Inc. (“NSPI” or the “Company”) is a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, Canada, providing electricity generation, transmission and distribution services to approximately 565,000 customers. NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia (“the Act”) and is subject to regulation by the Nova Scotia Energy Board (“NSEB”, formerly the Nova Scotia Utility and Review Board). The Company’s accounting policies are subject to examination and approval by the NSEB.

NSPI is a wholly owned subsidiary of Emera Incorporated (“Emera”). NSPI holds a 100 per cent investment in NS Power Energy Marketing Incorporated (“NSPEMI”), an energy business that purchases and sells electricity and natural gas in the United States (“US”) energy commodity market. Intercompany balances and intercompany transactions have been eliminated on consolidation.

NSPI has a 50 per cent indirect voting interest in Wasoqonatl Transmission Incorporated (“WTI”) and accounts for its investment as an equity investment (refer to note 25 for additional details).

Basis of Presentation

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

All dollar amounts are presented in Canadian dollars (“CAD”), unless otherwise indicated.

Principles of Consolidation

These consolidated financial statements include the accounts of NSPI and its wholly-owned subsidiary, NSPEMI.

The Company performs ongoing analysis to assess whether it holds any variable interest entities (“VIE”). To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity.

Use of Management Estimates

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

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. The rates are designed to recover prudently incurred costs of providing the regulated products or services and provide an opportunity for a reasonable rate of return on invested capital, as applicable (refer to note 5 for additional details).

Foreign Currency Translation

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

Revenue Recognition

Regulated electric revenue:

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

Other:

Other revenues are recorded when obligations under the terms of the contract are satisfied.

Property, Plant and Equipment

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

The cost of additions, including betterments and replacements of units are included in "PP&E" on the Consolidated Balance Sheets. When units of regulated PP&E are replaced, renewed, or retired, their cost, plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, ARO and overhead attributable to the capital project. Overhead includes costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance.

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

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. The service lives of assets are determined based on formal depreciation studies and are approved by the NSEB. The last depreciation study was completed in 2025 and remains subject to approval. The last depreciation study approved was completed in 2010.

Intangible assets, which are included in "PP&E" on the Consolidated Balance Sheets, consist primarily of land rights and computer software with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the assets in each category. The estimated service lives of intangible assets requires regulatory approval.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing regulated construction projects and is capitalized to the cost of PP&E until the asset is operational. The Company includes an equity cost component in AFUDC, in addition to a charge for borrowed funds. AFUDC is a non-cash item and cash is realized under the rate-making process over the service life of the related PP&E through future revenues resulting from a higher rate base and recovery of higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to "Interest expense, net", while the equity component is included as a reduction to "Other income, net". AFUDC is calculated using a weighted average cost of capital, as per the method of calculation approved by the NSEB and is compounded semi-annually.

Income Taxes and Investment Tax Credits

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

Investment tax credits are recorded as a reduction to current income tax expense in the year they are utilized.

NSPI collects income taxes from customers based on income tax that is currently payable except for the deferred income taxes on certain regulatory balances specifically prescribed by the NSEB. For the balance of regulated deferred income taxes, NSPI recognizes regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets.

NSPI classifies interest and penalties associated with unrecognized tax benefits in the Consolidated Statements of Income as “Interest expense, net” and “OM&G”, respectively. Refer to note 7 for further details.

Derivatives and Hedging Activities

NSPI's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. The Company has established several processes and practices to identify, monitor, report on and mitigate material risks to the Company. A corporate team independent from operations is responsible for tracking to report on market and credit risks.

The Company manages its exposure to normal operating and market risks relating to commodity prices, and foreign exchange through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, and coal, oil, natural gas and purchased power, options, forwards, and swaps. Collectively, these contracts are considered derivatives.

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

Derivatives entered into by NSPI, that are documented as economic hedges or for which the NPNS exception has not been taken, are subject to regulatory accounting treatment, as approved by the NSEB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled. The NSEB has approved that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

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

NSPI classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory, OM&G and PP&E, depending on the nature of the item being economically hedged. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on the Consolidated Statements of Cash Flows. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

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

Leases

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

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

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

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

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

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

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

Cash, Cash Equivalents and Restricted Cash

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

Receivables and Allowance for Credit Losses

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity sales are 30 days for bi-monthly customers and 20 days for monthly customers. A late payment fee may be assessed on account balances after the due date.

The Company recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Credit risk assessments are conducted on all new customers and deposits are requested on any high-risk accounts in accordance with the Company's policy. The Company also maintains provisions for expected credit losses, which are assessed on a regular basis.

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

Inventory

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

Asset Impairment

Long-lived assets and intangibles are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. NSPI bases its evaluation of long-lived assets and intangibles on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors. If the sum of the undiscounted cash flows expected from an asset is less than the carrying value of the asset, the asset is written down to fair value.

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

Asset Retirement Obligations

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

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of "Depreciation and amortization". Differences between accretion expense recognized for rate regulatory purposes and USGAAP, and accretion expense not yet approved by the NSEB, are deferred to "PP&E" and included in the next depreciation study.

As at December 31, 2025 and 2024, some of the Company's transmission and distribution assets may have conditional AROs which are not recognized in the consolidated financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations, and a liability is recognized at fair value in the period in which an amount can be determined.

Cost of Removal

The Company recognizes non-ARO costs of removal (“COR”) as regulatory liabilities or regulatory assets. The non-ARO COR represents funds received from customers through depreciation rates to cover estimated future non-legally required cost of removal and decommissioning of PP&E upon retirement, net of the costs incurred by the Company for non-legally required cost of removal and decommissioning activities. The Company accrues removal costs over the life of the related assets based on the depreciation studies approved by the NSEB. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays.

Stock-Based Compensation

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

Employee Benefits

The costs of the Company’s pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCL. The components of net periodic benefit cost other than the service cost component are included in “Other income, net” on the Consolidated Statements of Income. Refer to note 14 for further details.

Government Grants

The Company accounts for government grants by applying a grant accounting model by analogy to International Accounting Standards (“IAS”) 20, *Accounting for Government Grants and Disclosure of Government Assistance*. A grant relating to an asset is reflected in the determination of the carrying amount of the asset. A grant relating to income is presented as a deduction from the related expense it is intended to compensate.

In 2025, the Company received an aggregate of \$74 million (2024 – \$39 million) of government grants from various Canadian government agencies towards capital projects included in PP&E. The capital projects receiving grants primarily relate to the Company’s decarbonization and environmental compliance initiatives. Further details on significant grant programs utilized in 2025 and 2024 are noted below.

Natural Resources Canada (“NRCan”) Smart Renewables & Electrification Pathways (“SREP”):

On March 27, 2024 NSPI was approved for a grant under the NRCan SREP program to fund the construction of three 50 MW battery storage systems in Nova Scotia. NSPI can make claims under the grant until March 31, 2027, for 33 per cent of total eligible project costs to a maximum \$109 million. For the year-end December 31, 2025, NSPI received \$45 million (2024 – \$26 million) in funding under the grant, which has been recorded as a reduction to the carrying amount of the project in PP&E.

NRCan Electricity Predevelopment Program ("EPP"):

In 2023 and 2024, NSPI was approved for grants under the NRCan EPP program to fund the pre-construction costs for various eligible clean energy projects. NSPI can make claims under the grants until March 31, 2026, for 100 per cent of total eligible project costs to a maximum of \$34 million. For the year-end December 31, 2025, NSPI received \$27 million (2024 – \$7 million) in funding under the grants, which has been recorded as a reduction to the carrying amount of the respective projects in PP&E.

Cybersecurity Incident

On April 25, 2025, NSPI discovered a cybersecurity incident (the "Cybersecurity Incident") involving unauthorized access into certain parts of its information technology ("IT") network and servers supporting portions of its business applications. There was no disruption to any of our physical operations.

During restoration efforts, the Company implemented business continuity processes for certain impacted business and administrative functions. 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. The Company maintains cyber insurance coverage and is working with the insurer on the claims process. In Q4 2025, the Company recognized \$1 million, after-tax, in costs related to the Cybersecurity Incident. For the year ended December 31, 2025, the Company recognized \$7 million in after-tax costs related to the Cybersecurity Incident.

2. CHANGE IN ACCOUNTING POLICY

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 disclosure provided in note 7.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all Accounting Standard Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by the FASB but as allowed, have not yet been adopted by NSPI. Any ASUs not included below were assessed and determined to be either not applicable to the Company or 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.

4. REVENUE

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

For the millions of dollars	Year ended December 31	
	2025	2024
Residential	\$ 1,073	\$ 997
Commercial	522	499
Industrial	270	276
Other	43	41
Electric revenue	1,908	1,813
Other revenue (1)	36	42
Operating revenues	\$ 1,944	\$ 1,855

(1) Includes revenue which does not represent revenues from contracts with customers.

Remaining Performance Obligations

Remaining performance obligations primarily represent the transaction prices of a long-term steam supply agreement. As of December 31, 2025, the aggregate amount of the transaction price allocated to remaining performance obligations was \$7 million. The Company expects to recognize revenue for the remaining performance obligations through Q3 2027.

5. REGULATORY MATTERS

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

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide an appropriate return to investors. NSPI's approved regulated return on equity ("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.

Regulatory Environment and Updates

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 the IESO Nova Scotia assumes responsibility for system operations. The establishment of the IESO Nova Scotia follows Bill 404 - Energy Reform (2024) Act enacted in April 2024, which established the NSEB, and phased transition to the IESO Nova Scotia.

General Rate Application ("GRA"):

On September 18, 2025, NSPI filed a consensus General Rate Application ("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.

Cybersecurity Incident:

On May 14, 2025, the NSEB initiated an inquiry into the Cybersecurity Incident. For further information on the "Cybersecurity Incident", refer to note 1.

Wasoqonatl Transmission Line:

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 "Investments subject to significant influence" on the Consolidated Balance Sheets. On November 20 2025, the NSEB for approved WTI's application of a \$685 million of capital investment, including AFUDC, for the reliability intertie.

Maritime Link:

The Maritime Link is a \$1.8 billion (including AFUDC) transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. The Maritime Link entered service on January 15, 2018, and NSPI started interim assessment payments to NSPML at that time.

Regulatory Assets and Liabilities

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

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

Regulatory assets and liabilities as at December 31, excluding certain regulatory assets related to PP&E and AROs as discussed in notes 13 and 20, consisted of the following:

As at millions of dollars	December 31 2025	December 31 2024
Regulatory assets		
Deferred income tax regulatory asset	\$ 1,081	\$ 922
FAM (refer to table below)	102	-
Hurricane Fiona	29	32
Deferrals related to derivative instruments	27	40
Cost of removal	17	8
Storm rider	-	23
Other	10	16
	\$ 1,266	\$ 1,041
Current	\$ 45	\$ 67
Long-term	1,221	974
Total regulatory assets	\$ 1,266	\$ 1,041
Regulatory liabilities		
Deferrals related to derivative instruments	\$ 25	\$ 44
FAM (refer to table below)	-	56
	\$ 25	\$ 100
Current	\$ 17	\$ 29
Long-term	8	71
Total regulatory liabilities	\$ 25	\$ 100

Deferred Income Tax Regulatory Asset:

NSPI recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the consolidated financial statements or income tax returns, in accordance with NSPI's rate-regulated accounting policy as approved by the NSEB. To the extent deferred income taxes are expected to be recovered from or returned to customers in future years, NSPI recognizes a net deferred income tax regulatory asset or liability as appropriate.

FAM:

NSPI has a NSEB approved FAM, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

Pursuant to the FAM Plan of Administration, NSPI's fuel costs are subject to independent audit. On October 16, 2025, the NSEB's decision on the FAM audit findings and recommendations relating to fiscal 2022 and 2023 were publicly released and included a disallowance of \$1 million plus associated interest. The impact of the disallowance was recorded in Q4 2025.

Hurricane Fiona:

NSPI has NSEB approved regulatory assets for the deferred recognition of \$25 million in incremental operating costs related to storm restoration efforts, and \$10 million of undepreciated costs related to assets retired, because of Hurricane Fiona in September 2022. Beginning on July 1, 2024, these regulatory assets are being amortized over a 10-year period.

Deferrals Related to Derivative Instruments:

NSPI defers changes in fair value of derivatives that are documented as economic hedges or that do not qualify for NPNS exception, as a regulatory asset or liability as approved by the NSEB. The realized gain or loss is recognized when the hedged item settles in "Fuel for generation and purchased power", "Other income, net", "Inventory", "OM&G" or "PP&E", depending on the nature of the item being economically hedged.

Storm Rider:

NSPI has a NSEB approved storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the NSEB for recovery of costs if major storm restoration expense exceeds approximately \$10 million in a given year. The storm rider was effective as of the February 2, 2023 GRA decision date. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application.

The change in the FAM regulatory (liability) asset balances consisted of the following:

millions of dollars	2025	2024
FAM regulatory (liability) asset – Balance January 1	\$ (56)	\$ 395
Total under (over) recovery of current period fuel costs (1)	161	(350)
Interest on FAM balance	(1)	21
FAM sale to Invest Nova Scotia (2)	-	(117)
2020 – 2021 FAM disallowance, including interest (3)	-	(4)
2022 – 2023 FAM disallowance, including interest (4)	(1)	-
Other	(1)	(1)
FAM regulatory (liability) asset – Balance December 31	\$ 102	\$ (56)

(1) 2024 includes the Q4 2024 refund of previous NSPML assessment payments, resulting in \$486 million over-recovery of fuel costs. For further details refer to the "Other Regulatory Matters" section below.

(2) 2024 includes the Q2 2024 sale of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. For further details refer to the "Other Regulatory Matters" section below.

(3) 2024 includes the Q1 2024 FAM disallowance related to the NSEB's decision on the FAM audit findings and recommendations relating to fiscal 2020 and 2021. The disallowance of \$3 million and \$1 million of associated interest expense, was returned to customers through the FAM.

(4) 2025 includes the Q4 2025 FAM disallowance related to the NSEB's decision on the FAM audit findings and recommendations relating to fiscal 2022 and 2023. The disallowance of \$1 million and associated interest expense, was returned to customers through the FAM.

FAM and Other Deferrals

"FAM and other deferrals" recognized in the Consolidated Statements of Income consisted of the following:

For the millions of dollars	Year ended December 31	
	2025	2024
FAM:		
Under (over)-recovery of fuel costs	\$ (161)	\$ 350
2020 – 2021 FAM disallowance, excluding interest	-	3
2022 – 2023 FAM disallowance, excluding interest	1	-
DSM Rider: Under-recovery of DSM program costs	(1)	(1)
Storm Rider: Recovery of deferred major storm restoration expense	23	(1)
Other	1	(1)
Total FAM and other deferrals	\$ (137)	\$ 350

The regulatory asset or liability balance associated with these deferrals as at December 31, 2025 (refer to the "Regulatory Assets and Regulatory Liabilities" section above) includes associated interest which is recorded as "Interest expense, net" on the Condensed Consolidated Statements of Income.

Other Regulatory Matters

Federal Loan Guarantee:

On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSP Maritime Link Inc. ("NSPML") and the Province of Nova Scotia on terms and conditions for a federal loan guarantee of \$500 million in debt to be issued by NSPML to help Nova Scotia customers manage unrecovered costs of the replacement energy that was required during the several years of delay in the Muskrat Falls hydroelectricity project. On November 29, 2024, the NSEB approved NSPML's application to issue the debt, transfer the proceeds to NSPI as a refund of a portion of previous NSPML assessment payments, and increase its annual assessment charge to NSPI to recover the refund and related financing costs over a 28-year period. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance.

FAM Asset Sale:

On April 17, 2024, the NSEB approved the sale of \$117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the \$117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. NSPI is collecting the amortization and financing costs related to the \$117 million from customers on behalf of Invest Nova Scotia over a 10-year period which began in Q2 2024 and is remitting those amounts to Invest Nova Scotia quarterly.

6. INTEREST EXPENSE, NET

As at millions of dollars	Year ended December 31	
	2025	2024
Interest on debt	\$ 181	\$ 197
Interest on FAM balance	1	(19)
Interest revenue, net	(7)	(9)
Allowance for borrowed funds used during construction	(8)	(6)
Other	5	5
	\$ 172	\$ 168

7. INCOME TAXES

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

millions of dollars	2025		2024	
Income before provision for income taxes	\$ 96		\$ 118	
Income taxes, at statutory income tax rate	14	15%	18	15%
Domestic reconciling items:				
Investment tax credits	(36)	(38%)	-	(0%)
Deferred income taxes on regulated income recorded as regulatory assets and liabilities	(19)	(20%)	(40)	(34%)
Net Part VI.1 tax	14	15%	14	12%
Other	1	1%	1	1%
Provincial income taxes (1)	(19)	(20%)	(35)	(30%)
Income tax recovery	\$ (45)	(47%)	\$ (42)	(36%)

(1) Provincial income taxes relate to Nova Scotia.

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

millions of dollars	2025			2024		
	Federal	Provincial	Total	Federal	Provincial	Total
Current income taxes	\$ (6)	\$ -	\$ (6)	\$ 29	\$ -	\$ 29
Deferred income taxes	21	19	40	(36)	(35)	(71)
Operating loss carryforwards	(41)	(38)	(79)	-	-	-
Income tax recovery	\$ (26)	\$ (19)	\$ (45)	\$ (7)	\$ (35)	\$ (42)

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

millions of dollars	2025		2024	
Deferred income tax assets:				
Tax loss carryforwards	\$	283	\$	191
ARO		59		56
Pension and post-retirement liabilities		35		36
Denied interest and financing expenses		31		-
Other		52		81
Total deferred income tax assets before valuation allowance		460		364
Valuation allowance		(43)		(10)
Total deferred income tax assets after valuation allowance	\$	417	\$	354
Deferred income tax liabilities:				
PP&E		(1,032)		(934)
Pension and post-retirement assets		(144)		(76)
Other		(100)		(83)
Total deferred income tax liabilities	\$	(1,276)	\$	(1,093)
Consolidated balance Sheets presentation:				
Long-term deferred income tax liabilities	\$	(859)	\$	(739)

As at December 31, 2025, NSPI had a net operating loss carryforward of \$919 million (2024 – \$615 million) which expires between 2042 and 2045, a gross capital loss carryforward of \$51 million (2024 – \$51 million) with an indefinite carryforward period and investment tax credits of \$2 million (2024 – \$1 million) which expire between 2039 and 2044.

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that NSPI is more likely than not to realize all recorded deferred income tax assets, except for the denied interest and financing expenses, capital loss carryforward and investment tax credits. A valuation allowance of \$43 million has been recorded as at December 31, 2025 (2024 – \$10 million) related to denied interest and financing expenses, the capital loss carryforward and investment tax credits.

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

millions of dollars	2025		2024	
Deferred income tax assets:				
Balance, January 1	\$	25	\$	22
Increases due to tax positions related to current year		4		5
Decreases due to tax positions related to prior year		(2)		(2)
Balance, December 31	\$	27	\$	25

Unrecognized tax benefits relate to the timing of certain tax deductions. The total amount of unrecognized tax benefits as at December 31, 2025 was \$27 million (2024 – \$25 million), which would decrease the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was \$12 million (2024 – \$10 million) with \$2 million interest expense recognized in the Consolidated Statements of Income in 2025 (2024 – \$1 million). No penalties have been accrued.

NSPI files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. As at December 31, 2025, NSPI's tax years still open to examination by taxing authorities include 2006 and subsequent years.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is \$126 million (2024 – \$126 million), including interest. NSPI has prepaid \$55 million (2024 – \$55 million), of the amount in dispute, as required by CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute of the 2006 through 2010 taxation years. Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the difference, if any, either owed to, or refunded from, the CRA. The related tax deductions will be available in subsequent years.

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

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

8. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

millions of dollars	Defined benefit pension and non-pension benefits	
	2025	2024
Balance, January 1	\$ (8)	\$ (78)
Amounts reclassified to AOCL	145	70
Balance, December 31	\$ 137	\$ (8)

The reclassifications into AOCI/AOCL are as follows:

millions of dollars	2025		2024	
	Affected line item in the Consolidated Financial Statements		Amount reclassified to AOCI/AOCL	
	(1)			
Amortization of actuarial losses	Other income, net	\$ 1	\$ 1	
Amounts reclassified to obligations	Pension and post-retirement liabilities	144		69
Total reclassifications into AOCI/AOCL for the period		\$ 145	\$	70

(1) These AOCL components are included in the computation of net periodic pension costs (refer to note 14 for additional details).

9. RECEIVABLES, NET

As at millions of dollars	December 31 2025	December 31 2024
Customer accounts receivable – billed	\$ 195	\$ 142
Customer accounts receivable – unbilled	260	202
Total customer accounts receivable	455	344
Allowance for credit losses	(7)	(3)
Customer accounts receivable, net	448	341
Cash collateral position on derivative instruments (note 11)	3	46
Sales tax receivable	44	15
Other	62	15
Total receivables, net	\$ 557	\$ 417

10. INVENTORY

As at millions of dollars	December 31 2025	December 31 2024
Fuel	\$ 185	\$ 184
Materials	114	111
Total inventory	\$ 299	\$ 295

11. DERIVATIVE INSTRUMENTS

Derivative assets and liabilities receiving regulatory deferral consisted of the following:

	Derivative Assets		Derivative Liabilities	
As at millions of dollars	December 31 2025	December 31 2024	December 31 2025	December 31 2024
Current				
Commodity swaps and forwards	\$ 14	\$ 12	\$ 19	\$ 28
Foreign exchange forwards	2	22	1	3
Total gross current derivatives	16	34	20	31
Impact of master netting agreements with the intent to settle net or simultaneously	(1)	(6)	(1)	(6)
Total current derivatives	15	28	19	25
Long-term				
Commodity swaps and forwards	\$ 8	\$ 12	\$ 6	\$ 14
Foreign exchange forwards	1	5	1	-
Total gross current derivatives	9	17	7	14
Impact of master netting agreements with the intent to settle net or simultaneously	-	(1)	-	(1)
Total long-term derivatives	9	16	7	13
Total derivatives	\$ 24	\$ 44	\$ 26	\$ 38

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

Regulatory Deferral

NSPI received approval from the NSEB for regulatory deferral of gains and losses on certain derivatives documented as economic hedges and certain physical contracts that do not qualify for the NPNS exception. Refer to note 5 for these regulatory deferrals. The Company has recorded the following changes with respect to derivatives receiving regulatory deferral:

For the millions of dollars	Year ended December 31			
	2025		2024	
	Commodity swaps and forwards	Foreign exchange forwards	Commodity swaps and forwards	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	\$ (34)	\$ 1	\$ (25)	\$ 5
Unrealized gain (loss) in regulatory liabilities	20	(12)	23	33
Realized gain in regulatory assets	(7)	-	(8)	-
Realized loss in regulatory liabilities	5	-	4	-
Realized (gain) loss in inventory (1)	15	(8)	12	(8)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	16	(4)	42	(6)
Total change in derivative instruments	\$ 15	\$ (23)	\$ 48	\$ 24

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period; hedging relationships that have been terminated or the hedged transaction is no longer probable.

Notional Volumes

As at December 31, 2025, the Company had the following notional volumes of commodity swaps and forwards and physical natural gas purchase contracts designated for regulatory deferral that are expected to settle as outlined below:

millions	2026	2027-2028
<i>Commodity swaps and forwards purchases:</i>		
Natural gas (MMBtu)	7	10
Power (MWh)	1	-

As at December 31, 2025, the Company had the following notional volumes of foreign exchange forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2026	2027-2028
Foreign exchange contracts (millions of US dollars ("USD"))	\$ 175	\$ 72
Weighted average rate	1.3569	1.3534
% of USD requirements	64%	16%

NSPI reassesses forecast foreign exchange requirements periodically and will enter into additional hedges or unwind existing hedges, as required.

Credit Risk

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

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

As at December 31, 2025, the maximum exposure the Company has to credit risk is \$567 million (December 31, 2024 – \$448 million), which includes accounts receivable, and assets related to derivatives net of collateral/deposits.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity prices and foreign exchange. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The total cash deposits/collateral on hand as at December 31, 2025, was \$14 million (December 31, 2024 – \$13 million). The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty when it is no longer required by the Company.

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

As at December 31, 2025, the Company had \$119 million (December 31, 2024 – \$56 million) in financial assets considered to be past due, which have been outstanding for an average of 90 days. The fair value of these financial assets is \$114 million (December 31, 2024– \$54 million), the difference of which is included in the allowance for credit losses. These assets relate to accounts receivable from electric revenue.

Concentration Risk

The Company's concentrations of risk as at December 31, consisted of the following:

As at	2025		2024	
	millions of dollars	% of total exposure	millions of dollars	% of total exposure
Receivables, net				
Residential	\$ 278	48%	\$ 206	45%
Commercial	89	15%	76	16%
Industrial	58	10%	41	9%
Other	126	22%	48	10%
Cash collateral	6	1%	46	10%
	557	96%	417	90%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	24	4%	44	10%
	24	4%	44	10%
	\$ 581	100%	\$ 461	100%

Cash Collateral

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables, net" and obligations to return cash collateral are recognized in "Accounts payable" on the Consolidated Balance Sheets. As at December 31, 2025, the Company's cash collateral position was a \$3 million receivable (December 31, 2024 – \$46 million receivable).

Collateral is posted in the normal course of business. Certain of the Company's derivatives could contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization. As at December 31, 2025, the total fair value of these derivatives, in a liability position, was \$26 million (December 31, 2024 – \$38 million).

12. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

As at millions of dollars	Level 1		Level 2		December 31, 2025 Level 3		Total
Assets							
<i>Regulatory deferral:</i>							
Commodity swaps and forwards	\$	21	\$	-	\$	-	\$ 21
Foreign exchange forwards		-		3		-	3
Total assets		21		3		-	24
Liabilities							
<i>Regulatory deferral:</i>							
Commodity swaps and forwards		11		13		-	24
Foreign exchange forwards				2		-	2
Total liabilities		11		15		-	26
Net assets (liabilities)	\$	10	\$	(12)	\$	-	(2)

As at	December 31, 2024			
millions of dollars	Level 1	Level 2	Level 3	Total
Assets				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	\$ 15	\$ 2	\$ -	\$ 17
Foreign exchange forwards	-	27	-	27
Total assets	15	29	-	44
Liabilities				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	18	17	-	35
Foreign exchange forwards	-	3	-	3
Total liabilities	18	20	-	38
Net (liabilities) assets	\$ (3)	\$ 9	\$ -	\$ 6

The financial liabilities included on the Consolidated Balance Sheets that are not measured at fair value consisted of long-term debt as follows:

As at millions of dollars	Carrying Amount		Fair Value		Level 1	Level 2	Level 3	Total
December 31, 2025	\$	3,615	\$	3,589	\$	-	\$	3,589
December 31, 2024	\$	3,342	\$	3,349	\$	-	\$	3,349

The fair values of long-term debt instruments, classified as Level 2 in the fair value hierarchy, are estimated based on the quoted market price from the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity.

13. PROPERTY, PLANT AND EQUIPMENT

As at millions of dollars	December 31 2025	December 31 2024
Generation	\$ 4,010	\$ 3,873
Transmission	1,495	1,276
Distribution	2,329	2,186
General plant and other	928	863
Total cost	8,762	8,198
Less: Accumulated depreciation	(3,716)	(3,499)
	5,046	4,699
Construction work in progress	339	275
Net book value	\$ 5,385	\$ 4,974

For the year ended December 31, 2025, AFUDC of \$17 million (2024 – \$13 million) was capitalized to “PP&E” on the Consolidated Balance Sheets.

As a result of NSEB approved accounting policies and depreciation rates, NSPI recognizes or defers certain costs within “PP&E” that would not otherwise be recognized or deferred in the absence of rate regulation. Cumulative differences between items recognized for rate regulatory purposes and USGAAP, including depreciation rates, AFUDC and overhead costs, cannot be separately determined. The cumulative increase to accretion expense included within accumulated depreciation as at December 31, 2025 was \$1 million (2024 – \$1 million).

There were no asset impairments of these assets for the years ended December 31, 2025, and 2024.

The estimated useful lives, in years, for each major category of PP&E consist of the following:

Generation	32 to 65
Generation - hydro	63 to 131
Generation - wind	25
Transmission	40 to 80
Distribution	14 to 65
General plant and other	5 to 50

The estimated average amortization expense for each of the five succeeding years is \$4 million for land rights and \$29 million for computer software.

14. EMPLOYEE BENEFIT PLANS

NSPI maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees.

Defined Benefit Plans

The Company maintains contributory defined benefit pension plans which cover approximately 30 per cent of the active workforce. The defined benefit plan pension benefits are determined based on the years of service and average salary at the time the employee terminates employment. The plan provides annual post-retirement indexing equal to the change in the Consumer Price Index up to a stated maximum. The measurement date for the defined benefit pension plan is December 31. Effective November 1, 2014, the defined benefit plan was closed to new entrants.

Other retirement benefit plans ("Non-pension benefit plans") include the unfunded retirement award plan (which is impacted by expected future salary increases) and contributory health care plan. The unfunded retirement award plan was closed to new entrants effective August 1, 2007.

Benefit Obligation and Plan Assets

The changes in benefit obligation and plan assets, and the funded status for all plans for the years ended December 31 were as follows:

millions of dollars	2025		2024	
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")	Defined benefit pension plan	Non-pension benefit plans	Defined benefit pension plan	Non-pension benefit plans
Balance, January 1	\$ 1,324	\$ 30	\$ 1,310	\$ 29
Service cost	9	1	10	1
Plan participant contributions	5	-	5	-
Interest cost	60	1	59	1
Benefits paid	(73)	(2)	(70)	(3)
Actuarial (gains) losses	(34)	-	10	2
Balance, December 31	\$ 1,291	\$ 30	\$ 1,324	\$ 30
Change in Plan assets				
Balance, January 1	\$ 1,464	\$ -	\$ 1,353	\$ -
Employer contributions	10	2	12	3
Plan participant contributions	5	-	5	-
Benefits paid	(73)	(2)	(70)	(3)
Actual return on assets, net of expenses	195	-	164	-
Balance, December 31	\$ 1,601	\$ -	\$ 1,464	\$ -
Funded Status, end of year	\$ 310	\$ (30)	\$ 140	\$ (30)

The actuarial losses recognized in the period for the defined benefit pension plans are as a result of losses associated with an updated salary increase assumption, higher than expected indexation, and member experience.

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

millions of dollars	2025		2024	
Plans with PBO/APBO in excess of plan assets	Defined benefit pension plan	Non-pension benefit plans	Defined benefit pension plan	Non-pension benefit plans
PBO/APBO	\$ 48	\$ 30	\$ 50	\$ 30
Fair value of Plan Assets	5	-	5	-
Funded Status	\$ (43)	\$ (30)	\$ (45)	\$ (30)

Plans with Accumulated Benefit Obligation ("ABO") in excess of Plan assets

The ABO for the defined benefit pension plans was \$1,240 million as at December 31, 2025 (2024 – \$1,270 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 is as follows:

millions of dollars	Defined benefit pension plans	
	2025	2024
ABO	\$ 47	\$ 49
Fair value of Plan Assets	5	5
Funded Status	\$ (42)	\$ (44)

Consolidated Balance Sheets

The amounts recognized in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of dollars	2025		2024	
	Defined benefit pension plan	Non-pension benefit plans	Defined benefit pension plan	Non-pension benefit plans
Current liabilities	\$ (4)	\$ (3)	\$ (5)	\$ (3)
Long-term Liabilities	(39)	(27)	(40)	(27)
Other assets	353	-	185	-
AOCI/AOCL	(134)	(3)	11	(3)
Net amount recognized at end of year	\$ 176	\$ (33)	\$ 151	\$ (33)

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI. The following tables summarize the change in AOCI:

millions of dollars	Actuarial gains
Defined Benefit Pension Plans	
Balance, January 1, 2025	\$ 11
Amortized in current period	(1)
Current year addition to AOCI	(144)
Balance, December 31, 2025	(134)
Non-pension benefits plan	
Balance, January 1, 2025	\$ (3)
Current year addition to AOCI	-
Balance, December 31, 2025	\$ (3)

millions of dollars	2025		2024	
	Defined benefit pension plan	Non-pension benefit plans	Defined benefit pension plan	Non-pension benefit plans
Actuarial gains (losses)	\$ (134)	\$ (3)	\$ 11	\$ (3)
Net amount AOCI/AOCL	\$ (134)	\$ (3)	\$ 11	\$ (3)

Benefit Cost Components

NSPI's net periodic benefit cost (recovery) as at December 31 included the following:

millions of dollars	2025		2024	
	Defined benefit pension plan	Non-pension benefit plans	Defined benefit pension plan	Non-pension benefit plans
Service cost	\$ 9	\$ 1	\$ 10	\$ 1
Interest cost	60	1	59	1
Expected return on plan assets	(85)	-	(83)	-
Current year amortization of:				
Actuarial losses	1	-	1	-
Total	\$ (15)	\$ 2	\$ (13)	\$ 2

The expected return on plan assets is determined based on the market-related value of plan assets of \$1,459 million as at January 1, 2025 (2024 – \$1,428 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

Pension Plan Asset Allocations

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

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers under the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic and global bonds, and short-term investments. NSPI reviews investment manager performance on a regular basis and maintains the plans' asset allocations within the ranges permitted in the pension plans' investment policy.

NSPI's target asset allocation for 2025 and 2024 was as follows:

Asset Class	2025 Target Range at Market			2024 Target Range at Market		
Short-term securities	0%	to	10%	0%	to	10%
Fixed Income	34%	to	49%	34%	to	49%
Equities						
Canadian	5%	to	15%	5%	to	15%
Non-Canadian (world)	37%	to	61%	37%	to	61%

The investment of the pension assets, including the performance of investment managers, is overseen by the NSPI Management Pension Committee. All pension investments are in accordance with the policies approved by the Board of Directors.

The fair value of investments as at December 31, 2025, by asset category, are as follows:

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	\$ -	\$ 10	\$ -	10	1%
Equity Securities:					
Canadian equity	-	114	-	114	7%
International equity	-	285	-	285	18%
Fixed income securities	-	-	6	6	0%
Open-ended investments measured at NAV (1)	1,186	-	-	1,186	74%
Total	\$ 1,186	\$ 409	\$ 6	1,601	100%

(1) NAV investments are comprised of open-ended fixed income, short-term investment, Canadian equity and international equity pooled funds. NAV's are calculated at least monthly and the funds honor subscription and redemption activity regularly.

The fair value of investments as at December 31, 2024, by asset category, are as follows:

millions of dollars	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	\$ -	\$ 12	\$ -	12	1%
Equity Securities:					
Canadian equity	-	107	-	107	7%
International equity	-	300	-	300	21%
Fixed income securities	-	-	48	48	3%
Open-ended investments measured at NAV (1)	997	-	-	997	68%
Total	\$ 997	\$ 419	\$ 48	1,464	100%

(1) NAV investments are comprised of open-ended fixed income, short-term investment, Canadian equity and international equity pooled funds. NAV's are calculated at least monthly and the funds honor subscription and redemption activity regularly.

Refer to note 12 for more information on the fair value hierarchy and inputs used to measure fair value.

Investments in Emera Incorporated or NSPI

As at December 31, 2025, and 2024, the assets related to the pension funds do not hold any material investments in Emera or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Post-retirement benefit plan assets

There are no assets set aside to pay for the other post-retirement benefit plans. As is common in Canada, post-retirement health benefits are paid from general accounts as required.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2026	\$ 10	\$ 3
Expected benefit payments		
2026	77	3
2027	78	3
2028	80	3
2029	81	3
2030	83	3
2031 - 2035	477	16

Assumptions

The following table shows the assumptions that have been used in accounting for the defined benefit pension and other post-retirement benefit plans as at December 31 included in the following:

millions of dollars	2025		2024	
(weighted average assumptions)	Defined benefit pension plan	Non-pension benefit plans	Defined benefit pension plan	Non-pension benefit plans
Benefit obligation				
Discount rate - past service	4.89%	4.41%	4.63%	4.34%
Discount rate - future service	5.07%	4.76%	4.72%	4.50%
Rate of compensation increase	2.75 - 4.00%	2.75 - 4.00%	2.75 - 4.00%	2.75 - 4.00%
Health care trend - initial (next year)	-	5.72%	-	5.86%
- ultimate	-	3.60%	-	3.60%
- year ultimate reached	-	2040	-	2040
Benefit costs				
Discount rate - past service	4.63%	4.34%	4.63%	4.62%
Discount rate - future service	4.72%	4.50%	4.62%	4.63%
Expected long-term return on plan assets	6.00%	-	6.00%	-
Rate of compensation increase	2.75 - 4.00%	2.75 - 4.00%	2.25 - 4.75%	2.25 - 4.75%
Health care trend - initial (current year)	-	5.86%	-	6.00%
- ultimate	-	3.60%	-	3.60%

The rate of compensation increases for the December 31, 2025, benefit obligation disclosure ranged from 2.75 per cent (age 45 and over) to 4.00 per cent (age 34 and under).

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

The discount rates are based on high-quality long-term Canadian corporate bonds, with maturities matching the estimated cash flows from the pension plan for future service and past service.

Defined Contribution Plan

The Company also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2025, was \$8 million (2024 – \$7 million).

15. LEASES

Lessee

NSPI has operating leases for office space, land, telecommunications services and rail cars. NSPI's leases have remaining lease terms of 1 year to 60 years, some of which include options to extend the leases for up to 51 years. These options are included as part of the lease term when it is considered reasonably certain that they will be exercised.

As at millions of dollars	Classification	December 31 2025	December 31 2024
Right-of-use asset	Other long-term assets	\$ 20	\$ 20
Lease liabilities:			
Current	Other current liabilities	1	-
Long-term	Other long-term liabilities	21	21
Total lease liabilities		\$ 22	\$ 21

For the year ended December 31, 2025, NSPI has recorded lease expense of \$116 million (2024 – \$113 million) of which \$115 million (2024 – \$112 million) relates to variable costs for power generation facility finance leases recognized in "Fuel for generation and purchased power".

As at December 31, 2025, future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Minimum lease payments	\$ 2	\$ 1	\$ 1	\$ 1	\$ 1	\$ 42	\$ 48
Less: Imputed interest							26
						\$	22

Additional information related to NSPI's leases for the year ended December 31, 2025, is as follows:

Weighted average remaining lease term	46
weighted average discount rate - operating leases	3.62%

Lessor

The Company's net investment in direct finance and sales-type leases relates to leases of heat pumps and other equipment.

The net investment in heat pump and other equipment leases consists of the following:

As at millions of dollars	December 31 2025	December 31 2024
Minimum lease payments to be received	\$ 28	\$ 39
Less: Unearned finance lease income	4	7
Net investment in direct finance and sales-type leases	\$ 24	\$ 32
Principal due within one year (included in "Receivables, net")	6	7
Net investment in direct finance and sales-type leases - long-term (included in "Other long-term assets")	\$ 18	\$ 25

The unearned income related to the direct finance and sales-type leases is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease and is recorded as "Other expenses, net" on the Consolidated Statements of Income. Customers have the option to purchase the heat pumps and other equipment at the end of the lease term for a nominal fee.

As at December 31, 2025, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Minimum lease payments to be received	\$ 7	\$ 6	\$ 5	\$ 4	\$ 3	\$ 3	\$ 28

16. RELATED PARTY TRANSACTIONS

The Company enters into transactions with Emera Inc. and other subsidiaries or investments of Emera Inc. in the normal course of operations. NSPI's related parties include investments accounted for using the equity method. As at December 31, 2025, related parties include Emera Inc., Brooklyn Power Corporation, Emera Energy Inc., Emera Energy Services, Inc., NSPML and the WTI equity investments. All related party transactions entered into by NSPI with its affiliates are governed by an Affiliate Code of Conduct approved by the NSEB.

Transactions between the Company and its related parties reported in the Consolidated Statements of Income and Consolidated Balance Sheets are as follows:

For the millions of dollars		Year ended December 31
Nature of Service	Presentation	2025 2024
Sales:		
Management and administrative, and other services	OM&G	\$ 13 \$ 19
Rent and other services	Operating revenues	2 2
Purchases:		
Maritime Link assessment	Fuel for generation and purchased power	185 (324)
Net purchase of electricity and natural gas	Fuel for generation and purchased power	36 31
Management and administrative, and other services	OM&G	13 11

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 Statement of Income.

On December 19, 2025, NSPI invested \$9 million in WTI and recorded this within "Investments subject to significant influence" on the Consolidated Balance Sheets. Equity earnings issued to NSPI from WTI for the year ended December 31, 2025 was nil. For further details refer to note 25.

For the year ended December 31, 2025, NSPI issued 0.04 million common shares (2024 – 0.04 million common shares) to Emera for total consideration of \$0.4 million (2024 – \$0.4 million) and returned \$340 million of capital (2024 – nil) to Emera without a reduction in the amount of common shares outstanding.

As at December 31, 2025, NSPI had \$185 million due to Emera and affiliates (December 31, 2024 – \$150 million).

17. SHORT-TERM DEBT

NSPI's short-term debt as at December 31 consisted of the following:

millions of dollars	2025		2024	
Term CORRA – non-revolving term facility (1)	\$	500	\$	-
Bank indebtedness		42		2
Total Short-term debt	\$	542	\$	2

(1) Canadian Overnight Repo Rate Average ("CORRA")

The Term CORRA – non-revolving term facility has a weighted average interest rate on outstanding short-term debt at December 31, 2025 was 3.35 per cent, and matures on May 21, 2026.

Financing Activity

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.

18. OTHER CURRENT LIABILITIES

As at	December 31		December 31	
millions of dollars	2025		2024	
Accrued charges	\$	61	\$	61
Accrued interest on long-term debt		40		41
Carbon tax payable		15		25
Sales tax payable		-		11
Other		4		4
Total other current liabilities	\$	120	\$	142

19. LONG-TERM DEBT

NSPI's long-term debt includes the issuances detailed below. Medium-term notes are issued under trust indentures at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year. Long-term debt as at December 31 consisted of the following:

millions of dollars	Interest Rate	Maturity	2025	2024
Discount notes (1)	Variable	2029	\$ 559	\$ 177
Revolving credit facility - BESS Project (2)	Variable	2047	74	19
Medium-term notes				
Series F	8.85%	2025	-	125
Series L	8.30%	2036	60	60
Series M (3)	8.50%	2026	40	40
Series N	7.60%	2097	50	50
Series P	6.28%	2029	40	40
Series R	7.45%	2031	75	75
Series S	6.95%	2033	200	200
Series V	5.67%	2035	150	150
Series W	5.95%	2039	200	200
Series X	5.61%	2040	300	300
Series Y	4.15%	2042	250	250
Series Z	4.50%	2043	300	300
Series AA	3.61%	2045	175	175
Series AB	3.57%	2049	400	400
Series 2020-1	3.31%	2050	300	300
Series 2023-1	4.95%	2032	300	300
Series 2023-2	5.36%	2053	200	200
			\$ 3,040	3,165
			\$ 3,673	3,361
Debt issuance costs			(18)	(19)
Amount due within one year			(40)	(125)
Long-term debt			\$ 3,615	\$ 3,217

(1) Discount notes are backed by a revolving credit facility which matures in 2029.

(2) NSPI has a revolving credit facility to finance the BESS Project.

(3) Notes are extendable until 2056 at the option of the holders.

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

millions of dollars	Maturity	2025	2024
Revolving credit facility (1)	June 2029	\$ 800	\$ 800
Total		\$ 800	\$ 800
Less:			
Face value of borrowings under credit facilities		561	177
Letters of credit issued inside the line of credit		17	12
Use of available facilities		\$ 578	\$ 189
Available capacity under existing agreements		\$ 222	\$ 611

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to \$50 million at prime rate borrowing. Overdraft advances are classified as short-term debt.

Credit Facilities

NSPI can issue up to \$800 million under its commercial paper program, of which the full amount outstanding is backed by the Company's operating credit facility. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

As at December 31, 2025, the revolving credit facility has standby fees of 0.2 per cent calculated on the limit of the revolving credit facility less any outstanding letters of credit. The weighted average interest rate on the outstanding borrowings on the revolving credit facility was 2.76 per cent as at December 31, 2025 (2024 – 3.88 per cent).

Debt Covenants

NSPI's debt obligations contain covenants related to the amount of debt to capitalization as defined in certain agreements. In addition, other covenants and financial reporting obligations exist. Failure to comply with these covenants could result in an event of default, which if not cured or waived, could result in the acceleration of outstanding debt obligations.

NSPI has debt covenants associated with its credit facilities. As at December 31, 2025 and 2024, NSPI was in compliance with all respective financial covenants related to outstanding debt. NSPI's significant covenant is listed below:

Instrument	Financial Covenant	Requirement/Restriction	Calculation as at
			December 31, 2025
Syndicated credit facility	Debt to capital ratio	Less than or equal to 0.70:1	0.68:1

Long-Term Debt Maturities

As at December 31, 2025, long-term debt maturities for each of the next five years and in aggregate thereafter are as follows:

Years of maturity	millions of dollars
2026	\$ 40
2027	-
2028	-
2029	599
2030	-
Greater than 5 years	3,034
Total	\$ 3,673

20. ASSET RETIREMENT OBLIGATIONS

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

The changes in ARO for the years ended December 31 are as follows:

millions of dollars	2025	2024
Balance, January 1	\$ 137	\$ 132
Accretion included in ARO liability	7	7
Liabilities settled	-	(2)
Balance, December 31	\$ 144	\$ 137

As at December 31, 2025, and 2024, some of the Company's transmission and distribution assets may have additional conditional AROs which are not recognized in the consolidated financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. Management will continue to monitor these obligations and a liability will be recognized in the period in which an amount becomes determinable.

21. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2025, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt, interest payment obligations, long-term payables and ARO) 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
Purchased power (1)	\$ 344	\$ 360	\$ 347	\$ 395	\$ 388	\$ 5,176	\$ 7,010
Transportation (2)	38	22	20	20	20	115	235
Maritime Link assessment	199	-	-	-	-	-	199
Solid fuel supply	193	-	-	-	-	-	193
Capital projects	95	24	7	3	1	-	130
Long-term service agreements (3)	30	17	14	12	8	6	87
DSM	64	-	-	-	-	-	64
Leases (4)	2	1	1	1	1	42	48
Natural gas supply	22	-	-	-	-	-	22
	\$ 987	\$ 424	\$ 389	\$ 431	\$ 418	\$ 5,339	\$ 7,988

(1) Represents NSPI's annual requirement to purchase 100 per cent of electricity production from Independent Power Producers and Community Feed-in Tariff participants over varying contract lengths up to 25 years based on estimated production volumes as well as agreements for the purchase of import power.

(2) Purchasing commitments for transportation of solid fuel and natural gas.

(3) Outsourced management of the Company's computer and communication infrastructure, software maintenance and support, shared service agreements at a co-generation facility, transmission and distribution line construction and maintenance services related to a generation facility and wind operating agreements.

(4) Operating leases for office space, land, telecommunications services, and rail cars.

NSPI has a contractual obligation to pay NSPML, a related party, for the 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 authorizing it to collect up to \$198.7 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. Refer to note 5.

B. Legal Proceedings

The Company may, from time to time, be involved in legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company. Any that arise that may be expected to have a material effect on the financial condition of the Company have been disclosed below:

Class Action Lawsuit

NSPI was named as a defendant in a claim for a class action lawsuit filed with the Supreme Court of Nova Scotia, seeking damages arising from the Cybersecurity Incident. The amount of damages has not been specified. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

C. Environment

NSPI's activities are subject to a broad range of federal, provincial, regional and local laws and environmental regulations, designed to protect, restore and enhance the quality of the environment including air, water and solid waste. This includes the federal and provincial governments goals to transition off coal and reach 80 per cent renewable electricity sales by 2030. Capital investment in Nova Scotia's grid will be required to integrate additional renewable energy into the system, while continuing to provide safe, reliable electricity to customers. NSPI is working with both levels of government to determine the appropriate funding in Nova Scotia to facilitate these projects while minimizing costs for customers. Capital investment by NSPI will be dependent on the sources of funding and ownership structures in place to facilitate these investments, therefore, the total impact to NSPI and incremental cost to customers of this clean energy transition is not known at this time.

NSPI estimates its environmental capital spending, excluding AFUDC, based upon present environmental laws and regulations will be approximately \$81 million during fiscal 2026 and is estimated to be \$111 million from 2027 through 2030. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 21. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and other pollutant emissions.

In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to the Company. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on the Company.

Conformance with legislative and Company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed to December 31, 2025.

Polychlorinated Biphenyl Equipment

In response to the Canadian Environmental Protection Act 1999, 2008 Polychlorinated Biphenyl ("PCB") Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other oil-filled electrical equipment on its system that fall under the 2008 PCB Regulations Standard by December 31, 2025. This also includes PCB contaminated pole mounted transformers. The combined total cost of these projects is estimated to be \$115 million and, as at December 31, 2025, approximately \$100 million (December 31, 2024 – \$92 million) has been spent to date. NSPI has recognized an ARO liability on the balance sheet of \$2 million as at December 31, 2025 (December 31, 2024 – \$2 million) associated with the PCB phase-out program.

On December 31, 2025, Environment & Climate Change Canada (ECCC) published amendments to the PCB Regulations in Canada Gazette Part II, providing an extended phase out deadline to December 31, 2026. NSPI is developing PCB Action Plan post-2025 recognizing there is also a targeted application-based extension program for facilities that will be closing before 2030, and for equipment where it would not be technically or economically feasible to replace the equipment by the end of 2026.

D. Principal Financial Risks and Uncertainties

In this section, NSPI describes some of the principal financial risks management believes could materially affect the Company in the normal course of business. Risks associated with derivatives and fair value measurements are discussed further in note 11 and note 12.

NSPI has a business-wide risk management process, monitored by the Board of Directors, to ensure risks are appropriately identified, assessed, monitored and subject to appropriate controls. The significant business risks to NSPI are described below, many of which are beyond the Company's control, and could have a material adverse effect on operations, liquidity or access to or cost of capital, financial position, prospects, and/or results of operations (herein considered a "Material Adverse Effect").

Regulatory and Political Risk

NSPI is 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. NSPI's is regulated under a cost-of-service model and 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 NSPI is 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 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.

Commodity Price Risk

The Company's fuel supply is subject to commodity price risk.

The Company's 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.

General Economic Risk

The Company has exposure to the macro-economic conditions in Nova Scotia. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity, and in turn the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could have 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:

NSPI utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk.

The allowed range of ROE will generally follow the direction of interest rates, such that it is likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. The cost of debt is a component of rates and prudently incurred debt costs are recovered from customers.

Interest rates could also be impacted by changes in credit ratings.

As at December 31, 2025, 75 per cent of NSPI's debt position is fixed rate in nature, with an average term to maturity of approximately 17 years.

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.

E. Guarantees and Letters of Credit

As at December 31, 2025, the Company had \$94 million USD (2024 - \$104 million USD) of guarantees outstanding with terms of varying lengths, all of which are issued on behalf of NSPEMI.

As at December 31, 2025, the Company had \$6 million USD and \$8 million CAD of letters of credit outstanding (December 31, 2024 - \$7 million USD and \$3 million CAD).

F. Collaborative Arrangements

For the years ended December 31, 2025 and 2024, the Company has identified the following material collaborative arrangements:

The Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI's portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI's portion of operating expenses is recorded in "OM&G" on the Consolidated Statements of Income.

NSPI is a participant in a 23.3 megawatt ("MW") wind energy project with Renewable Energy Services Ltd. in Point Tupper, Nova Scotia, with NSPI owning 47.4 per cent. In 2025, NSPI recognized \$3 million net expense (2024 - \$2 million) in "Fuel for generation and purchased power".

NSPI is a participant in a 102 MW wind energy project with the South Canoe Development Partnership for South Canoe Wind Farm, in New Ross, Nova Scotia, with NSPI owning 49 per cent. In 2025, NSPI recognized a \$7 million (2024 – \$8 million) net expense in “Fuel for generation and purchased power” and \$3 million (2024 – \$3 million) in “OM&G”.

NSPI is a participant in a 13.8 MW wind energy project with the Municipality of the District of Guysborough for Sable Wind Farm, near Canso, Nova Scotia, with NSPI owning 49 per cent. In 2025, NSPI recognized a \$2 million (2024 – \$2 million) net expense in “Fuel for generation and purchased power”.

22. STOCK-BASED COMPENSATION

EMPLOYEE COMMON SHARE PURCHASE PLAN

Eligible employees may participate in Emera’s Employee Common Share Purchase Plan (“ECSPP”). As of December 31, 2025, the plan allows employees to make cash contributions of a minimum of \$25 to a maximum of \$20,000 per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employee’s contributions to the plan.

The plan allows the reinvestment of dividends except where it is prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares (2024 – 7 million common shares).

Compensation cost for shares issued by Emera for the year ended December 31, 2025, to employees of NSPI under the ECSPP was \$2 million (2024 – \$2 million) and is included in “OM&G” on the Consolidated Statements of Income.

SHARE UNIT PLANS

The Company participates in Emera’s DSU, PSU and RSU plans. The plans and the liabilities are marked-to-market at the end of each period based on the closing Emera common share price on the last trading day before the end of the period.

Deferred Share Unit Plan

Under the Directors’ DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors’ fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera’s common shares, the Director’s DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the Board, the value of the DSUs credited to the participant’s account is calculated by multiplying the number of DSUs in the participant’s account by Emera’s closing common share price on the date the DSUs are redeemed.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50 per cent of the value of their actual annual incentive award (25 per cent in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When short-term incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Unless otherwise determined by the Emera Management Resources and Compensation Committee ("MRCC"), following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2025, is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2024	46,363 \$	48.87	126,243 \$	46.68
Granted including Dividend Reinvestment Program ("DRIP")	2,215	48.87	16,199	51.12
Exercised	N/A	N/A	(19,631)	53.44
Transferred	N/A	N/A	N/A	N/A
Outstanding as at December 31, 2025	48,578 \$	48.87	122,811 \$	46.18

Compensation cost recognized for employee and director DSUs for the year ended December 31, 2025, was \$3 million (2024— \$1 million). Tax benefits realized related to this compensation cost was \$1 million for share units in 2025 (2024 - nil). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2025, was \$12 million (2024 – \$9 million). Cash payments made during the year ended December 31, 2025 associated with the DSU plan were \$6 million (2024 - nil).

Performance Share Unit Plan

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

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in certain departure scenarios. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee PSUs for the year ended December 31, 2025, is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value (millions of dollars)
Outstanding as at December 31, 2024	78,740	\$ 51.78	\$ 4
Granted including DRIP	38,881	52.63	
Exercised	(9,111)	59.77	
Forfeited	(11,603)	57.52	
Transferred	556	56.64	
Outstanding as at December 31, 2025	97,463	\$ 50.71	\$ 7

Compensation cost recognized for the PSU plan for the year ended December 31, 2025, was \$3 million (2024 – \$2 million). Tax benefits realized related to this compensation cost was \$1 million for share units in 2025 (2024 - nil). Cash payments made during the year ended December 31, 2025, associated with the PSU plan were nil (2024 – \$1 million).

Restricted Share Unit Plan

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

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee RSUs for the year ended December 31, 2025, is presented in the following table:

	Employee RSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value (millions of dollars)
Outstanding as at December 31, 2024	75,495	\$ 51.59	\$ 4
Granted including DRIP	38,779	52.63	
Exercised	(15,472)	59.77	
Forfeited	(3,837)	51.16	
Transferred	555	56.64	
Outstanding as at December 31, 2025	95,520	\$ 50.73	\$ 6

Compensation cost recognized for the RSU plan for the year ended December 31, 2025, was \$3 million (2024 – \$1 million). Tax benefits realized related to this compensation cost was \$1 million for share units in 2025 (2024 – nil). Cash payments made during the year ended December 31, 2025, associated with the PSU plan were \$1 million (2024 – \$1 million).

23. REDEEMABLE PREFERRED STOCK

On August 30, 2024, NSPI authorized 800,000 redeemable preferred shares and issued 400,000 redeemable preferred shares ("Series A") at a par value of \$25 per share to finance the Battery Energy Storage System Project. As at December 31, 2025, NSPI has 400,000 redeemable preferred shares (December 31, 2024 – 400,000 shares) outstanding at a par value of \$10 million (December 31, 2024 – \$10 million). Redeemable preferred shares are accounted for as a liability and recorded in "Redeemable preferred stock" on the Consolidated Balance Sheets and the redeemable preferred share dividends are recorded in "Interest expense, net" on the Consolidated Statements of Income.

24. SEGMENT INFORMATION

NSPI's consolidated operations represents a single reportable segment. The Company's single operating and reportable segment is in one regulatory environment, geographical region, and revenue is primarily derived from the sale of rate-regulated electricity. The Company's chief operating decision maker is the Company's President and Chief Executive Officer. The Company's net income and the presentation of accounts used in deriving net income reported to the Company's chief operating decision maker is consistent with the Condensed Consolidated Statement of Income. All operations and PP&E reside in the Province of Nova Scotia, Canada.

25. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

	Carrying Value as at		Percentage of Ownership (2)
	December 31 2025	December 31 2024	
millions of dollars			2025
WTI (1)	\$ 9	\$ -	50%

(1) Equity earnings issued for the three months and year ended December 31, 2025 was nil.

(2) NSPI's ownership interest is based on a 50 per cent indirect voting interest in WTI. As of December 31, 2025, NSPI's economic interest based on the \$9 million invested is 26%.

On March 5, 2025, NSPI, the Canada Infrastructure Bank ("CIB") and the Wskijinu'k Mtmo'taqnuow Agency ("WMA") announced the Wasoqonatl transmission line project which will 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.

26. VARIABLE INTEREST ENTITIES

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

For the year ended December 31, 2025, NSPI has not identified any new VIEs.

27. SUBSEQUENT EVENTS

These consolidated financial statements and notes reflect NSPI's evaluation of events occurring subsequent to the balance sheet date through February 23, 2026, the date the financial statements were issued.



Management's Discussion & Analysis

As at February 23, 2026

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Nova Scotia Power Inc. during the fourth quarter of 2025 relative to the same quarter in 2024; for the full year of 2025 relative to 2024 and selected financial information for 2023; and its financial position as at December 31, 2025 relative to 2024. Throughout this discussion, "NSPI" and "Company" refer to Nova Scotia Power Inc. and its consolidated subsidiary NS Power Energy Marketing Incorporated ("NSPEMI").

This discussion and analysis should be read in conjunction with the NSPI annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2025. NSPI follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). Additional information related to NSPI, including the Company's Annual Information Form, can be found on SEDAR+ at www.sedarplus.ca.

NSPI's accounting policies are subject to examination and approval by the Nova Scotia Energy Board ("NSEB", formerly the Nova Scotia Utility and Review Board). The rate-regulated accounting policies of NSPI may differ from those used by non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues, and expenses.

All amounts are in Canadian dollars ("CAD"), unless otherwise stated.

FORWARD-LOOKING INFORMATION

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations include, without limitation: regulatory and political risk; change in law risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; changes in credit ratings; rate base growth; timing and costs associated with certain capital investments; expected impacts on NSPI 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; 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 system 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 forward-looking information, as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, NSPI undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

INTRODUCTION AND STRATEGIC OVERVIEW

NSPI is a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, Canada. NSPI has \$8.1 billion of assets and provides electricity generation, transmission and distribution services to approximately 565,000 customers. NSPI owns approximately 5,000 kilometres of transmission facilities and 29,000 kilometres of distribution facilities. To ensure reliability of service, NSPI aims to maintain access to generating capacity greater than firm peak demand. NSPI owns 2,422 Megawatts ("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 4-hour grid-scale battery facilities to further enhance reliability. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP") and community feed in tariff ("COMFIT") participants, which own 573 MW of capacity. This includes IPPs in which NSPI has an ownership interest. 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. In 2025, NSPI derived more than 40 per cent of its electric sales from renewable sources and achieved a 49 per cent reduction in generation from solid fuel compared to 2005 levels.

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 is working closely with the provincial government as the Province aims to transition off coal and reach 80 per cent renewable electricity sales by 2030. These are ambitious goals set by the federal and provincial governments to address climate change. NSPI is working with the provincial government as it pursues these goals, while continuing to provide safe and reliable electricity to customers. For further details on the renewable energy transition, developments related to provincial and federal environmental laws and regulations, and risks around achieving climate-related and environmental legislative requirements refer to the “Outlook – Environmental Legislation and Climate Change” section below.

NSPI is a wholly-owned subsidiary of Emera Incorporated (“Emera”). NSPI holds a 100 per cent investment in NSPEMI, an energy business that purchases and sells electricity and natural gas in the United States of America’s energy commodity market. NSPI holds a 50 per cent indirect voting interest in Wasoqonatl Transmission Incorporated (“WTI”), for further details refer to the “Outlook – Developments” section.

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

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

NSPI has a NSEB approved Fuel Adjustment Mechanism (“FAM”) allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods. Refer to note 5 of NSPI’s consolidated financial statements as at December 31, 2025 for further details on NSPI’s regulatory mechanisms.

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect the demand for energy and cost of service. Results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

OUTLOOK

Operations

NSPI’s earnings are most directly impacted by the range of ROE and capital structure approved by the NSEB, the prudent management and approved recovery of operating costs, electric sales volumes, weather, the approved recovery of regulatory deferrals and the timing and amount of capital investment.

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 range in 2026 and expects earnings in 2026 to be higher than 2025. For further details on the GRA and the settlement agreement refer to the “Developments” section. Sales volumes are expected to be higher in 2026 than 2025. Capital investment for 2026, including allowance for funds used during construction (“AFUDC”), is expected to be approximately \$720 million (2025 – \$712 million). NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

Environmental Legislation and Climate Change

NSPI is subject to environmental laws and regulations as set by both the Government of Canada and the Nova Scotia Provincial Government (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 climate initiatives and 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 the 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.

Air Quality Regulations:

On March 25, 2025, NSPI received a Certificate of Variance (“COV”) from Nova Scotia Environment and Climate Change (“NSECC”) which provides flexibility on the timing of sulfur dioxide (“SO₂”) emissions over the 2025 through 2034 period, including compensating for excess emissions in 2022. The flexibility lowers compliance costs for customers without increasing total emissions over the period.

DEVELOPMENTS

General Rate Application (“GRA”):

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.

Wasoqonatl Transmission Line:

On March 5, 2025, NSPI, the Canada Infrastructure Bank (“CIB”) and the Wskijinu’k Mtmo’taqnuow Agency (“WMA”) announced the Wasoqonatl transmission line project which will 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 “Investments subject to significant influence” on the Consolidated Balance Sheets. On November 20, 2025, the NSEB approved WTI’s application of a \$685 million capital investment, including AFUDC, for the reliability intertie.

Cybersecurity Incident:

On April 25, 2025, NSPI discovered a cybersecurity incident (the “Cybersecurity Incident”) involving unauthorized access into certain parts of its IT network and servers supporting portions of its business applications. There was no disruption to any of NSPI’s physical operations.

The Company implemented business continuity processes for certain impacted business and administrative functions. The systematic restoration of affected IT systems and corresponding transition away from business continuity process continues to progress in a planned, controlled and phased approach. The Company maintains cyber insurance coverage and is working with the insurer on the claims process. In Q4 2025, the Company recognized \$1 million, after-tax, in costs related to the Cybersecurity Incident. For the year ended December 31, 2025, the Company recognized \$7 million in after-tax costs related to the Cybersecurity Incident. For information on the risks associated with cybersecurity incidents generally, refer to the 'Enterprise Risk and Risk Management' section.

Class Action Lawsuit:

NSPI was named as a defendant in a claim for a class action lawsuit filed with the Supreme Court of Nova Scotia, seeking damages arising from the Cybersecurity Incident. The amount of damages has not been specified. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

Appointments

Effective February 11, 2025, Dan Muldoon joined the NSPI Board of Directors. Mr. Muldoon retired as the Executive Vice President, Project Development and Operations Support at Emera in 2025.

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

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.

FINANCIAL REVIEW OF 2025

Consolidated Statements of Income

For the millions of dollars	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Operating revenues	\$ 504	\$ 479	\$ 1,944	\$ 1,855
Fuel for generation and purchased power	269	(216)	1,065	509
FAM and other deferrals	(29)	436	(137)	350
Operating, maintenance and general ("OM&G")	107	95	370	350
Demand-side management ("DSM")	16	15	63	58
Provincial grants and taxes	12	12	49	48
Depreciation and amortization	77	73	298	282
Total operating expenses	452	415	1,708	1,597
Income from operations	52	64	236	258
Other income, net	(7)	(7)	(32)	(28)
Interest expense, net	43	42	172	168
Income before provision for income taxes	16	29	96	118
Income tax recovery	(6)	(42)	(45)	(42)
Net income	\$ 22	\$ 71	\$ 141	\$ 160

Highlights of the changes are summarized in the following table:

For the millions of dollars	Three months ended December 31	Year ended December 31
Net income – 2024	\$ 71	\$ 160
Increased operating revenues (refer to "Operating Revenues" section for explanation)	25	89
Increased fuel for generation and purchased power (refer to "Fuel for Generation and Purchased Power" section for explanation)	(485)	(556)
Increased FAM and other deferrals (refer to note 5 of NSPI's audited consolidated financial statements as at December 31, 2025 for explanation)	465	487
Increased OM&G expenses quarter-over-quarter due to increased storm costs and costs related to the Cybersecurity Incident (for further details on the Cybersecurity Incident refer to the "Developments" section). Year-over-year 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 allocated to property, plant and equipment ("PP&E")	(12)	(20)
Increased depreciation and amortization due to increased PP&E in-service	(4)	(16)
Decreased income tax recovery quarter-over-quarter 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	(36)	3
Other	(2)	(6)
Net income – 2025	\$ 22	\$ 141

Operating Revenues

NSPI's operating revenues include sales of electricity and other services as summarized in the following table:

For the millions of dollars	Three months ended December 31	Year ended December 31
	2025	2025
Electric revenues	\$ 495	\$ 1,908
Other revenues	9	36
Operating revenues	\$ 504	\$ 1,944

Electric Revenues

NSPI's electric revenues are affected by rates approved by the NSEB and electric sales volumes. NSPI's electric revenues include revenues related to the recovery of fuel costs and non-fuel costs. The FAM allows NSPI to recover all prudently incurred fuel and certain fuel-related costs and consequently, revenues related to the recovery of fuel costs do not have a material impact on NSPI's net income.

Electric sales volumes are primarily driven by weather, number of customers, customer usage, general economic conditions, and DSM activities. Residential and commercial electricity sales are seasonal, with the first quarter historically generating the highest sales, reflecting colder weather and fewer daylight hours in the winter season.

NSPI's residential customers include individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other electric customers consist primarily of municipal electric utilities, users of street and area lighting services, and export energy customers.

Electric Sales Volume

For the Gigawatt hours ("GWh")	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Residential	1,411	1,343	5,292	5,096
Commercial	766	763	3,084	3,046
Industrial	535	569	2,098	2,217
Other	57	57	231	222
Total	2,769	2,732	10,705	10,581

Electric Revenues

For the millions of dollars	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Residential	\$ 285	\$ 260	\$ 1,073	\$ 997
Commercial	132	128	522	499
Industrial	67	69	270	276
Other	11	10	43	41
Total	\$ 495	\$ 467	\$ 1,908	\$ 1,813

Highlights of the changes in electric revenues are summarized in the following table:

For the millions of dollars	Three months ended December 31	Year ended December 31
Electric revenues – 2024	\$ 467	\$ 1,813
Increased electricity pricing effective January 1, 2025, and February 18, 2025	18	64
Increased sales volumes due to favourable weather	9	30
Excluding the impact of weather, increased residential and commercial sales volumes	6	14
Excluding the impact of weather, decreased industrial sales volumes	(5)	(13)
Electric revenues – 2025	\$ 495	\$ 1,908

Fuel for Generation and Purchased Power

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 NSP Maritime Link Inc. ("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 ("OBPS"), availability of renewable generation, including the NS Block, plant performance, and compliance with environmental regulations.

The high availability and capability of thermal generating stations continue to play a role in providing reliable energy to customers while NSPI is transitioning to more renewable generation. In 2025, thermal plant availability was 80 per cent compared to 82 per cent in 2024 and a four-year average of 81 per cent. The four-year average availability is in line with industry comparisons.

Production volumes by fuel type and average fuel cost are summarized in the following table:

For the GWh (except as indicated)	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Coal	1,329	976	4,370	3,347
Natural gas	377	516	1,403	2,317
Purchased power	33	118	391	620
Oil	93	64	295	132
Petcoke	44	40	279	374
Total non-renewables	1,876	1,714	6,738	6,790
Purchased Power - IPP, COMFIT and imports	638	608	2,573	2,086
NS Block	306	444	1,134	1,378
Wind, hydro and solar	134	151	855	932
Biomass	54	48	174	140
Total renewables	1,132	1,251	4,736	4,536
Total production volumes	3,008	2,965	11,474	11,326
Average fuel cost in dollars per Megawatt hour ("MWh") (1)	\$ 89	\$ (73)	\$ 93	\$ 45

(1) In Q4 2024, NSPI received refund of previous NSPML assessment payments, resulting in \$486 million over-recovery of fuel costs. For further details refer to note 5 of NSPI's consolidated financial statements as at December 31, 2025.

Average fuel costs per MWh increased in Q4 2025 compared to Q4 2024 primarily due to a refund of previous NSPML assessment payments received in Q4 2024. For further details, refer to Note 5 in the NSPI Consolidated Financial Statements as of December 31, 2025. Increase in the average fuel cost per MWh were primarily driven by increased generation from solid fuel and oil, and lower delivery of the NS Block due to prior period make-up energy being fully received contributed to the increase in average fuel costs per MWh. These were partially offset by favourable commodity prices driven by changes in solid fuel and decreased OBPS compliance costs.

Average fuel costs per MWh increased year-to-date 2025 compared to 2024 primarily due to a refund of previous NSPML assessment payments received in Q4 2024. For further details, refer to Note 5 in the NSPI Consolidated Financial Statements as of December 31, 2025. Increase in the average fuel cost per MWh were driven by increased generation from solid fuel and oil, lower delivery of the NS Block due to prior period make-up energy being fully received, and reduced generation from hydro assets due to drier weather conditions contributed to the increase in average fuel costs per MWh. These were partially offset by decreased generation from natural gas.

Highlights of the changes in fuel for generation and purchased power are summarized in the following table:

For the millions of dollars	Three months ended December 31	Year ended December 31
Fuel for generation and purchased power – 2024	\$ (216)	\$ 509
Increased Maritime Link assessment (refer to note 5 of NSPI's consolidated financial statements as at December 31, 2025, and "Transactions with related parties" for further details)	492	510
Change in generation mix	15	70
Increased sales volumes	2	16
(Decreased) increased Nova Scotia OBPS carbon tax	(3)	4
Decreased commodity prices	(22)	(45)
Other	1	1
Fuel for generation and purchased power – 2025	\$ 269	\$ 1,065

FAM and FAM Regulatory Deferral

NSPI has a NSEB approved FAM, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

Pursuant to the FAM Plan of Administration, NSPI's fuel costs are subject to independent audit. On October 16, 2025, the NSEB's decision on the FAM audit findings and recommendations relating to fiscal 2022 and 2023 were publicly released and included a disallowance of \$1 million plus associated interest. The impact of the disallowance was recorded in Q4 2025.

Refer to note 5 of NSPI's consolidated financial statements as at December 31, 2025, for further details on the FAM regulatory asset and associated regulatory matters.

Provincial Grants

NSPI pays annual grants to the Province in lieu of municipal taxation other than deed transfer tax.

Income Taxes

In 2025, NSPI was subject to a combined Canadian federal and Nova Scotia provincial statutory corporate income tax rate of 29 per cent (2024 – 29 per cent). In 2025, NSPI's effective tax rate was (47) per cent (2024 – (36) per cent) primarily due to investment tax credits and deferred income taxes on regulated income recorded as regulated assets and regulated liabilities.

Consolidated Balance Sheet Highlights

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

millions of dollars	Increase (Decrease)	Explanation
Assets		
Receivables, net	\$ 140	Increased due to timing of billing and receipts, partially offset by decreased cash collateral position on derivative instruments
Income taxes receivable	40	Increased due to clean technology investment tax credits
Derivative instruments (current and long-term)	(20)	Decreased due to weakening of the CAD dollar compared to the United States dollar ("USD")
Regulatory assets (current and long-term)	225	Increased deferred income tax regulatory asset and deferrals related to FAM, partially offset by decreased deferrals related to storm rider and derivative instruments.
Pension and post-retirement assets (current and long-term)	168	Increased due to higher investment returns and changes in actuarial assumptions
Property, plant and equipment, net of accumulated depreciation	411	Increased due to capital investment, partially offset by depreciation
Liabilities and Equity		
Bank indebtedness	\$ 40	Increased due to financing working capital requirements
Short-term debt	500	Increased due to addition of non-revolving term credit facility
Long-term debt (current and long-term)	313	Increased debt levels for general corporate purposes
Accounts payable	103	Increased due to timing of activity and related payments
Due to related parties (current and long-term)	35	Increased due to timing of payments
Regulatory liabilities (current and long-term)	(75)	Decreased deferrals related to FAM and derivative instruments
Other current liabilities	(22)	Decreased due to lower sales tax payable and decreased accrued OBPS carbon tax
Deferred income taxes	120	Increased due to tax deductions in excess of accounting depreciation related to PP&E, changes in pension and post-retirement assets and liabilities and an increase in FAM regulatory asset, partially offset by an increase in tax loss carryforwards
Other long-term liabilities	16	Increased due to increased customer deposits
Common stock	(340)	Decreased due to return of capital
Accumulated other comprehensive income (loss)	145	Decreased due to higher investment returns, favourable changes in actuarial assumptions and amortization
Retained earnings	141	Increased due to net income

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash primarily through the generation, transmission and distribution of electricity. NSPI's customer base is diversified by both sales volumes and rates among customer classes. Circumstances that could affect the Company's ability to generate cash include changes to global macroeconomic conditions, downturns in NSPI's markets, impact of fuel commodity price changes on collateral requirements and timely recoveries of fuel costs from customers, the loss of one or more large customers, regulatory decisions affecting customer rates, the recovery of regulatory assets, the accelerated payment of regulatory liabilities, changes in environmental legislation, political interference in the regulatory process, continued access to an investment grade credit rating and changes in weather patterns.

NSPI's future liquidity and capital needs will be predominantly for working capital requirements, ongoing rate base investment and debt servicing. In 2026, NSPI expects to invest approximately \$720 million, including AFUDC, primarily in capital projects required to support power system reliability and reliable service for customers.

NSPI has access to a \$800 million syndicated revolving bank line of credit and a \$500 million non-revolving term facility with a combined \$222 million available as at December 31, 2025. For further details, 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, beginning of period	\$ -	\$ 78	\$ (78)
Provided by (used in):			
Operating cash flow before change in working capital	293	831	(538)
Change in working capital	(175)	88	(263)
Operating activities	118	919	(801)
Investing activities	(631)	(483)	(148)
Financing activities	513	(514)	1,027
Cash, end of period	\$ -	\$ -	\$ -

Cash Flow from Operating Activities

Net cash provided by operating activities decreased \$801 million to \$118 million in 2025 compared to \$919 million in 2024.

Operating cash flow before change in working capital decreased \$538 million primarily due to increased fuel for generation and purchased power, 2024 including proceeds of \$117 million from the FAM regulatory asset sale, and increased OM&G expenses, partially offset by increased electric revenues due to increased electricity pricing and increased residential and commercial sales, increased current income tax recovery due to clean technology investment tax credits (offset in working capital), recovery of storm rider deferral, and decreased interest expense on the revolving credit facility.

Changes in working capital decreased cash flows by \$263 million primarily due to changes in accounts receivable, fuel inventory, and income taxes receivable (offset in operating cash flow).

Cash Flow used in Investing Activities

Net cash used in investing activities increased \$148 million to \$631 million in 2025 compared to \$483 million in 2024 due to higher capital investment.

Cash Flow from Financing Activities

Net cash provided by financing activities increased \$1,027 million to \$513 million in 2025 compared to net cash used in financing activities of \$514 million in 2024 primarily due to net borrowings under revolving credit facility in 2025 compared to net repayments in 2024, issuance of short-term debt, higher short-term bank indebtedness and higher proceeds from long-term debt, partially offset by return of capital to Emera in 2025 and retirement of long-term debt.

Working Capital

As at December 31, 2025, NSPI's working capital increased to \$567 million from \$468 million in 2024 primarily due to changes in accounts receivable, changes in income taxes receivable, and changes in other current liabilities, partially offset by changes in accounts payable, and changes in cash collateral positions on derivative instruments.

NSPI's future liquidity and capital needs will be predominately for working capital requirements, capital investment, dividends and debt servicing. Working capital is financed through internally generated cash flows and short-term credit facilities. The Company's expected future cash flows, credit facilities and continued access to debt capital markets for long-term financing is expected to be sufficient to meet the Company's requirements.

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
Purchased power (1)	\$ 344	\$ 360	\$ 347	\$ 395	\$ 388	\$ 5,176	\$ 7,010
Long-term debt (2)	40	-	-	599	-	3,034	3,673
Interest payment obligations (3)	169	165	165	156	147	1,785	2,587
Asset retirement obligations	2	-	-	-	-	302	304
Transportation (4)	38	22	20	20	20	115	235
Maritime Link assessment	199	-	-	-	-	-	199
Solid fuel supply	193	-	-	-	-	-	193
Capital projects	95	24	7	3	1	-	130
Pension and post-retirement obligations (5)	11	11	10	10	7	45	94
Long-term service agreements (6)	30	17	14	12	8	6	87
DSM	64	-	-	-	-	-	64
Leases (7)	2	1	1	1	1	42	48
Natural gas supply	22	-	-	-	-	-	22
	\$ 1,209	\$ 600	\$ 564	\$ 1,196	\$ 572	\$ 10,505	\$ 14,646

(1) Represents NSPI's annual requirement to purchase 100 per cent of electricity production from IPPs and COMFIT participants over varying contract lengths up to 25 years based on estimated production volumes as well as agreements for the purchase of import power.

(2) NSPI's discount notes are backed by a revolving credit facility which matures in 2029.

(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 as at December 31, 2025.

(4) Purchasing commitments for transportation of solid fuel and natural gas.

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

(6) Outsourced management of the Company's computer and communication infrastructure, software maintenance and support, shared service agreements at a co-generation facility, transmission and distribution line construction and maintenance services related to a generation facility and wind operating agreements.

(7) Operating leases for office space, land, telecommunications services, and rail cars.

NSPI has a contractual obligation to pay NSPML, a related party, for the 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. Refer to note 5 of NSPI's consolidated financial statements as at December 31, 2025 for further details.

Capital Investment

Forecast 2026 and actual 2025 and 2024 capital investment, including AFUDC, is shown below:

millions of dollars	2026 Forecast	2025 Actual	2024 Actual
Distribution	\$ 195	\$ 174	\$ 175
Generation	183	216	151
Transmission	247	242	107
General plant and other	95	80	54
Total	\$ 720	\$ 712	\$ 487

Debt Management

NSPI has access to a syndicated revolving bank line of credit and a non-revolving term facility. NSPI also has an active commercial paper program for up to \$800 million, of which the full amount outstanding is backed by the Company's operating credit facility. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable. As at December 31, 2025, the Company's total credit facility, outstanding borrowings and available capacity were as follows:

millions of dollars	Maturity	Credit Facility	Utilized	Available Capacity
Revolving credit facility	June 2029	\$ 800	\$ 578	\$ 222
Non-revolving term facility	May 2026	500	500	-

NSPI has debt covenants associated with its credit facilities. Covenants are tested regularly, and the Company is in compliance with covenant requirements as at December 31, 2025. NSPI's significant covenant is listed below:

Instrument	Financial Covenant	Requirement/Restriction	Calculation as at December 31, 2025
Syndicated credit facility	Debt to capital ratio	Less than or equal to 0.70:1	0.68:1

Financing Activity

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.

Credit Ratings

On January 22, 2025, S&P Global Ratings affirmed its BBB- issuer rating and revised its outlook to stable from negative.

On December 5, 2025, DBRS affirmed its BBB (high) rating and stable trend for NSPI.

Share Capital

For the year ended December 31, 2025, the Company issued 0.04 million (2024 – 0.04 million) common shares to Emera for total consideration of \$0.4 million (2024 – \$0.4 million) and returned \$340 million of capital (2024 – nil) to Emera without a reduction in the amount of common shares outstanding. As at December 31, 2025, NSPI had 173.5 million common shares issued and outstanding (2024 – 173.5 million common shares).

PENSION FUNDING

For funding purposes, NSPI determines required contributions to its registered defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a five-year period. The cash required in 2026 for defined benefit pension plans is expected to be \$10 million (2025 – \$12 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

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

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

NSPI's projected contributions to the defined contribution pension plans are \$9 million for 2026 (2025 – \$8 million).

OFF-BALANCE SHEET ARRANGEMENTS

Defeasance

Upon privatization of the former provincially owned Nova Scotia Power Corporation ("NSPC") in 1992, NSPI was appointed to manage and administer a portfolio of defeasance securities. The securities provide principal and interest streams to match the related defeased debt of NSPC, which as at December 31, 2025, totaled \$200 million (2024 – \$200 million).

The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), 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.

Under the privatization agreements, NSPI administers the defeasance cash flows and obligations pursuant to a Management and Administration Agreement. The NSPFC bank accounts are included in NSPI's pool of bank accounts under a mirror netting agreement and therefore, from time to time, if any cash accumulates in the NSPFC bank account it is available until that cash is required to service the defeased NSPC debt.

Guarantees and Letters of Credit

As at December 31, 2025, the Company had \$94 million USD (2024 - \$104 million USD) of guarantees outstanding with terms of varying lengths, all of which are issued on behalf of NSPEMI.

As at December 31, 2025, the Company had \$6 million USD and \$8 million CAD of letters of credit outstanding (December 31, 2024 - \$7 million USD and \$3 million CAD).

TRANSACTIONS WITH RELATED PARTIES

The Company enters into transactions with Emera Inc. and other subsidiaries or investments of Emera Inc. in the normal course of operations. NSPI's related parties include investments accounted for using the equity method. As at December 31, 2025 related parties include Emera Inc., Brooklyn Power Corporation, Emera Energy Inc., Emera Energy Services, Inc., NSPML and the WTI equity investments. All related party transactions entered into by NSPI with its affiliates are governed by an Affiliate Code of Conduct approved by the NSEB.

Transactions between the Company and its related parties reported in the Consolidated Statements of Income and Consolidated Balance Sheets are as follows:

For the millions of dollars		Year ended December 31	
Nature of Service	Presentation	2025	2024
Sales:			
Management and administrative, and other services	OM&G	\$ 13	\$ 19
Rent and other services	Operating revenues	2	2
Purchases:			
Maritime Link assessment	Fuel for generation and purchased power	185	(324)
Net purchase of electricity and natural gas	Fuel for generation and purchased power	36	31
Management and administrative, and other services	OM&G	13	11

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 Statement of Income.

On December 19, 2025, NSPI invested \$9 million in WTI and recorded this within "Investments subject to significant influence" on the Consolidated Balance Sheets. Equity earnings issued to NSPI from WTI for the year ended December 31, 2025 was nil. For further details refer to note 25 of NSPI's audited consolidated financial statements as at December 31, 2025.

For the year ended December 31, 2025, NSPI issued 0.04 million common shares (2024 – 0.04 million common shares) to Emera for total consideration of \$0.4 million (2024 – \$0.4 million) and returned \$340 million of capital (2024 – nil) to Emera without a reduction in the amount of common shares outstanding.

As at December 31, 2025, NSPI had \$185 million due to Emera and affiliates (December 31, 2024 – \$150 million).

ENTERPRISE RISK AND RISK MANAGEMENT

NSPI has a business-wide risk management process which is monitored by the Board of Directors, and also reviewed with the Emera Enterprise Risk Management Committee to ensure risks are appropriately identified, assessed, monitored and subject to appropriate controls.

The significant business risks to NSPI are described below, many of which are beyond the Company's control, and could have a material adverse effect on 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

NSPI is 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. NSPI's is regulated under a cost-of-service model and 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 NSPI is 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 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.

Aspects of the IESO Nova Scotia, once fully operational and during transition period, remain uncertain. Refer to Changes in Environmental Legislation.

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.

NSPI 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 NSPI to respond in an effective and timely manner to such future legislative, policy or regulatory changes.

Changes in Environmental Legislation

NSPI is subject to extensive regulation by federal, provincial and municipal 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.

Both the Province and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. The Province 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 comply with applicable legislation or regulation could result in a Material Adverse Effect. NSPI continues to work with both the provincial and federal governments on measures to seek to address their carbon reduction goals.

Per- and polyfluoroalkyl substances ("PFAS"):

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, it may impact NSPI'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 which could result in a Material Adverse Effect.

Greenhouse Gas Emissions:

NSPI is subject to GHG emission caps for the 2010 through 2030 period as outlined in the "Nova Scotia Greenhouse Gas Regulations", and further updated by Order in Council in 2013. The emission cap reduces from 10 megatonnes in 2010 to 4.5 megatonnes in 2030. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Pursuant to an Equivalency Agreement entered into between the Province and the Government of Canada in 2014 and renewed through 2029, these provincial regulations have been deemed equivalent to, and have exempted Nova Scotia from the application of federal GHG emissions regulations which would effectively require the retirement or conversion of coal-fired electricity generating units by the earlier of 50 years from commissioning or 2030. Over the decade, NSPI will work to comply with the decreasing emission caps through a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

The "Pan-Canadian Framework on Clean Growth and Climate Change" under the "Greenhouse Gas Pollution Pricing Act" put in place the legal mechanism for increasing the carbon tax in Canada by \$15 per tonne annually and reaching \$170 per tonne by 2030 beginning in 2023. Effective in 2023, the Province enacted amendments to the "Environment Act" which provided the framework for Nova Scotia to implement an OBPS to comply with these Government of Canada regulations. NSPI is a mandatory registrant under the OBPS.

The "Canadian Net-Zero Emissions Accountability Act" outlines the federal objective of attaining net-zero emissions by 2050. Further, the federal government's "2030 Emission Reduction Plan", required under the "Canadian Net-Zero Emissions Accountability Act", introduced the federal intention of attaining a net-zero electricity grid by 2035. On December 17, 2024, ECCC released a finalized version of the Clean Electricity Regulations (CER). The CER establish performance standards to significantly limit GHG emissions from fossil fuel-generated electricity starting in 2035 and help facilitate the Government of Canada's intention of achieving a net-zero electricity grid by the same year. NSPI continues to work with both the provincial and federal governments on measures to address their carbon dioxide reduction goals.

Renewable Energy Regulations:

The Province has established targets with respect to the percentage of renewable energy in NSPI's generation mix. Under the RER, the Company currently has a provincially mandated target of achieving at least 40 per cent of energy sales generated from renewable sources each year from 2020 through 2029. Beginning in 2030, the RER mandates that 80 per cent of electric sales be generated from renewable sources. Further, the Nova Scotia "Environmental Goals and Climate Change Reduction Act" established the goal to phase out coal-fired electricity generation by 2030. NSPI continues to work with both the provincial and federal governments on measures to address generation mix targets.

On April 6, 2023, the Province levied a \$10 million penalty on NSPI for non-compliance with the RER compliance period ending in 2022. 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.

Nova Scotia Energy Reform Act:

On April 5, 2024, the Province enacted Bill 404 - Energy Reform (2024) Act. This legislation implements certain recommendations made by the Clean Electricity Solutions Task Force, which was established by the Province to advise the provincial government on Nova Scotia's transition away from coal to more renewable sources of energy. The legislation enacted the Energy and Regulatory Board Act, which established the NSEB. The NSEB will regulate energy and utility entities in Nova Scotia, with a mandate of increased focus on meeting energy transition demands. The legislation also enacts the More Access to Energy Act, which provides for the establishment and phased transition to the Nova Scotia Independent Energy System Operator. NSPI is fully engaged in working with the Province on these initiatives.

On October 15, 2025, the 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 the IESO Nova Scotia assumes responsibility for system operations.

Air Quality Regulations:

NSPI is subject to emission cap requirements for mercury, SO₂ and nitrogen oxide ("NO_x") as prescribed in the Regulations. The Regulations limit net mercury emissions to 35 kg per year for the period of 2020 through 2029. NSPI is eligible to remit 10 kg of mercury credits per year to comply with the annual cap. Beginning in 2021, emissions compliance periods for NO_x came into effect, as outlined in the Regulations as follows:

Year	NO _x Caps (tonnes)
2021-2024 ¹	56,000
2025	11,500
2026-2029	44,000
2030	8,800

¹NO_x four-year cap for 2021-2024 is 56 tonnes, with no single year exceeding 14.995 tonnes.

Beginning in 2025, emissions compliance periods for SO₂ came into effect, as outlined in the Certificate of Variance as follows:

Year	SO₂ Caps (tonnes)
2025	45,000
2026	45,000
2027	40,000
2028	28,000
2030	9,000
2031	9,000
2032	9,000
2033	9,000
2034	9,000

NSPI is currently within, or forecasts the ability to meet, the prescribed limits for the current compliance periods. For the compliance periods ending in 2022, NSPI exceeded the prescribed limits for Mercury and SO₂. As per the Regulations, NSPI can compensate for the excess Mercury and SO₂ emissions within the three years following the year of exceedance, by reducing emissions equal to the amount of the excess emissions or can apply for an exemption by the Minister citing “unusual and unavoidable circumstances”. NSPI compensated for the excess mercury emissions within three years ending in 2025.

NSPI received a Certificate of Variance from NSECC on March 25, 2025, which provides flexibility on the timing of SO₂ emissions over the 2025 through 2034 period, including compensating for the excess 14,410 tonnes of SO₂ emissions in 2022. The flexibility lowers compliance costs for customers without increasing total emissions over the period.

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 coal-fired generation, 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, 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 NSPI 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 weather seasonal 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, the price of energy commodities, such as fuel, 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, 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 the slowing of customer growth in the Company's service territory, which could have a Material Adverse Effect.

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 it is found to be responsible for such a fire, the Company could suffer material costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes. If not recovered through these means or if recovery is delayed, they 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, 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 (refer to "Changes in 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, 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

NSPI 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 the Company 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, exercising and improving cybersecurity incident readiness and response programs, by hiring third-party cybersecurity experts, and employee communication and training. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and IT including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation and Northeast Power Coordinating Council that have been approved by the NSEB. The status of key elements of the Company's cybersecurity program is reported to the Board of Director on a quarterly basis. 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

NSPI is 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 NSPI'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. NSPI may enter foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases and capital investment. Currency forwards are used to fix the CAD cost to acquire USD, reducing exposure to currency rate fluctuations. NSPI's regulatory framework permits the recovery of prudently incurred costs, including foreign exchange. The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

The risk due to fluctuation of the CAD against the USD for fuel purchases is measured and managed. In 2026, NSPI expects approximately 41 per cent of its anticipated net fuel costs to be denominated in USD. Forward contracts to buy \$175 million USD were in place as at December 31, 2025, at a weighted average rate of \$1.3569, representing 64 per cent of 2026 anticipated USD requirements. Forward contracts to buy \$62 million USD in 2027 at a weighted average rate of \$1.3541 were in place as at December 31, 2025. These contracts cover 27 per cent of anticipated USD requirements in 2027. As at December 31, 2025, there were no fuel-related foreign exchange swaps outstanding. NSPI reassesses foreign exchange forecasts periodically and will enter into additional hedges or unwind existing hedges, as required.

Liquidity and Capital Market Risk

Liquidity risk relates to NSPI's ability to ensure sufficient funds are available to meet its financial obligations. NSPI's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent NSPI from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. NSPI's operations require significant capital investments and the risk associated with changes in interest rates that could have an adverse effect on the cost of financing. Inability to access cost-effective capital could have a material impact on NSPI to fund its operations. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions.

The Company 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, wildfires, and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings or increased borrowing costs under certain existing credit facilities. 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.

General Economic Risk

The Company has exposure to the macro-economic conditions in Nova Scotia. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity, and in turn the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could have 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:

NSPI utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk.

The allowed range of ROE will generally follow the direction of interest rates, such that it is likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. The cost of debt is a component of rates and prudently incurred debt costs are recovered from customers.

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

As at December 31, 2025, 75 per cent of NSPI's debt position is fixed rate in nature, with an average term to maturity of approximately 17 years.

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 to NSPI. 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, 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 could result 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 and municipal levels. There is no assurance that NSPI 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 Credit Risk

The Company 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 NSPI. The Company 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.

Commercial Relationship Risk

The Company is exposed to commercial relationships risk in respect of its reliance on certain key partners, suppliers and customers. For the year ended December 31, 2025, NSPI's five largest customers contributed approximately 7 per cent (2024 – 9 per cent) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues and could have a Material Adverse Effect.

Supply Chain Risk

NSPI's ability to meet customer energy requirements, respond to storm-related disruptions and invest in capital 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, labor 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:

NSPI is also exposed to the risk of fuel supply chain disruptions, both within and outside NSPI's service territory. Fuel supply disruptions which 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 NSPI, disruption to utility operations, and adverse reputational impacts, any of which could have a Material Adverse Effect.

Commodity Price Risk

The Company's fuel supply is subject to commodity price risk.

The Company's 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.

Subject to available liquidity in suitable hedging products, NSPI targets to be 50-100 per cent hedged for 2026 and 50-90 per cent hedged for 2027. NSPI reassesses fuel consumption forecasts quarterly and will enter into additional hedges or unwind existing hedges, as required, to rebalance the portfolio and ensure the objective of fuel cost stability is maintained while minimizing transaction costs.

Coal:

A substantial portion of NSPI's coal supply comes from international suppliers, which was contracted at or near the market prices prevailing at the time of contract. The Company has entered into fixed-price and index price contractual arrangements for forecast quantities of coal with several suppliers, as part of the fuel procurement portfolio strategy. As at December 31, 2025, the approximate percentage of forecast coal requirements hedged is 81 per cent for 2026 and 8 per cent for 2027.

Petcoke:

As at December 31, 2025, the approximate percentage of forecast petcoke requirements for 2026 is 23 per cent.

Natural Gas:

NSPI periodically enters into physical and/or financial contracts based on forecast natural gas consumption to meet load and system security requirements. Volumes exposed to market prices are managed using financial instruments in accordance with NSPI's hedging program. As at December 31, 2025, the approximate percentage of forecast natural gas requirements hedged for 2026 is 99 per cent and 2027 is 55 per cent.

Heavy Fuel Oil:

NSPI periodically enters into physical and/or financial contracts based on forecast heavy fuel oil purchases to meet load and system security requirements. Volumes exposed to market prices are managed using financial instruments in accordance with NSPI's hedging program. As at December 31, 2025, forecast heavy fuel oil requirements are fully hedged for 2026.

Power Purchases:

NSPI has fixed price agreements relating to NLH's NS Block energy delivery obligations and power purchase agreements with IPPs. NSPI also periodically enters into additional physical and/or financial contracts based on forecast power purchases to meet load and system security requirements. Volumes exposed to market prices are managed using financial instruments in accordance with NSPI's hedging program. As at December 31, 2025, the approximate percentage of forecast power purchase requirements hedged is 84 per cent for 2026 and 48 per cent hedged for 2027.

Future Employee Benefit Plan Performance and Funding Risk

NSPI has both defined benefit and defined contribution employee benefit plans that cover both employees and retirees. The defined benefit plan is closed to new entrants. The cost of providing the defined benefit plan varies depending on the 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 costs are investment performance, interest rates and inflation, which are affected by global financial and capital markets. Depending on future interest rates, future inflation and actual versus expected investment performance, NSPI could be required to make larger contributions in the future to fund these plans, which could have a Material Adverse Effect.

Labour Risk

NSPI's ability to deliver service to its customers 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 42 per cent of the full-time and term employees within the NSPI labour force are represented by a union and subject to a collective labour agreement, which expires March 31, 2026. The inability to maintain or negotiate future agreements on acceptable terms could result in high labour costs and work disruptions, which could adversely affect service, which could adversely affect service to customers and have a Material Adverse Effect. There have been no labour disruptions since 1975.

Technology Risk

NSPI relies on various technology systems to manage operations, including increasing reliance on IT solutions operated by third parties, such as software as a service and third party cloud hosting. This subjects NSPI 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 investment, 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. NSPI'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, and any such changes could have a Material Adverse Effect. The value of NSPI'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 transmission and distribution systems is critical to NSPI's operations. There are a variety of hazards and operational risks inherent in operating electric utilities. 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, other natural disasters. Electric utility transmission and distribution operation interruption could negatively affect customer and public confidence, and public safety, cause damage to our infrastructure or third-party property, and have a Material Adverse Effect.

Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all of these losses, which could have a Material Adverse Effect. The regulatory framework for NSPI permits the recovery of prudently incurred costs.

Uninsured Risk

NSPI maintains 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 NSPI's transmission and distribution assets are not insured, as is customary in the industry, as the cost of coverage is prohibitive. In addition, NSPI 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

NSPI's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are monitored by the Board of Directors. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company, including the establishment of the Credit Risk Oversight Committee. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks. Management reports quarterly on non-financial risks to the Board of Directors.

The Company manages its exposure to normal operating and market risks relating to commodity prices, and foreign exchange, through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, and coal, oil, natural gas and purchased power options, forwards and swaps. Collectively these contracts are considered derivatives.

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

Derivatives entered into by NSPI, that are documented as economic hedges or that do not qualify for NPNS exception, are subject to regulatory accounting treatment, as approved by the NSEB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The realized gain or loss is recognized when the hedged item settles in fuel for generation and purchased power, inventory or PP&E, depending on the nature of the item being economically hedged. Management believes that any gains or losses resulting from settlement of these fuel related derivatives will be refunded or collected from customers in future rates through the FAM.

Regulatory Items Recognized on the Consolidated Balance Sheets

The Company has the following categories on the Consolidated Balance Sheets related to derivatives receiving regulatory deferral:

As at millions of dollars	December 31 2025	December 31 2024
Derivative instrument assets (current and other assets)	\$ 24	\$ 44
Regulatory assets (current and other assets)	27	40
Derivative instrument liabilities (current and long-term liabilities)	(26)	(38)
Regulatory liabilities (current and long-term liabilities)	(25)	(44)
Net asset	\$ -	\$ 2

Regulatory Impact Recognized in Net Income

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

For the millions of dollars	Year ended December 31	
	2025	2024
Fuel for generation and purchased power (1)	\$ (12)	\$ (36)

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

Various valuation techniques are used to determine the fair value of derivative instruments at the reporting date. These may include quoted market prices or internal models using observable or non-observable market information.

DISCLOSURE AND INTERNAL CONTROLS

In accordance with National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, the Chief Executive Officer and Chief Financial Officer of the Company will file a Venture Issuer Basic Certificate with respect to the Company's annual consolidated financial statements and annual MD&A. This Venture Issuer Basic Certificate is not required to include representations relating to the establishment and maintenance of:

- I. controls and other procedures designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation ("DC&P"); and
- II. a process to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP ("ICFR").

The issuer's certifying officers are responsible for ensuring that processes are in place to provide them with sufficient knowledge to support the representations they are making in this certificate. Investors should be aware that limitations on the certifying officers' design and implementation on a cost effective basis of DC&P and ICFR may result in additional risks to the quality, reliability, transparency and timeliness of interim and annual filings and other reports provided under securities legislation.

CHANGE IN ACCOUNTING POLICY

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 disclosure provided in note 7.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024
Operating revenues	\$ 504	\$ 405	\$ 436	\$ 599	\$ 479	\$ 399	\$ 423	\$ 554
Net income	\$ 22	\$ 3	\$ 6	\$ 110	\$ 71	\$ 14	\$ 18	\$ 57

Quarterly operating revenues and net income are affected by seasonality. The first quarter is the strongest period, reflecting colder weather and fewer daylight hours. Seasonality and other weather patterns, including the number and severity of storms, can affect demand for energy and the cost of service.

Q4 2025 compared to Q4 2024

Q4 2025 net income decreased by \$49 million compared to Q4 2024. The decrease is due to decreased income tax recovery and increased OM&G expenses. Income tax recovery decreased due to the utilization of tax loss carryforwards recognized as a deferred income tax regulatory liability in 2024 and decreased tax deductions in excess of accounting depreciation related to PP&E. OM&G expenses increased due to higher storm costs and costs related to the Cybersecurity Incident.

Q3 2025 compared to Q3 2024

Q3 2025 net income decreased by \$11 million compared to Q3 2024. The decrease is due to increased OM&G expenses, and increased depreciation and amortization due to increased PP&E in service. OM&G expenses increased due to higher costs for transmission and distribution operations, and power generation operations, partially offset by higher administrative overhead allocated to PP&E.

Q2 2025 compared to Q2 2024

Q2 2025 net income decreased by \$12 million compared to Q2 2024. The decrease is due to increased OM&G expenses, and increased depreciation and amortization due to increased PP&E in service. OM&G expenses increased due to higher costs for power generation operations and costs related to the Cybersecurity Incident (for further details on the Cybersecurity Incident refer to the "Developments" section), partially offset by higher administrative overhead allocated to PP&E.

Q1 2025 compared to Q1 2024

Q1 2025 net income increased by \$53 million compared to Q1 2024. The increase is due to decreased income tax expense due to recognition of clean technology investment tax credits in 2025 and increased operating revenues due to increased sales volumes primarily driven by favourable weather.

SUMMARY OF SELECTED ANNUAL CONSOLIDATED FINANCIAL INFORMATION

The following table sets forth selected annual consolidated financial information of the Company for the three years ended December 31:

millions of dollars	2025	2024	2023
Operating revenues	\$ 1,944	\$ 1,855	\$ 1,671
Net income	\$ 141	\$ 160	\$ 141
Total assets	\$ 8,084	\$ 7,117	\$ 7,221
Total long-term debt	\$ 3,615	\$ 3,217	\$ 3,868



Nova Scotia Power Incorporated **Management Information Circular 2026**

Nova Scotia Power Incorporated
2026 Annual Meeting of Common Shareholders
May 21, 2026

MANAGEMENT INFORMATION CIRCULAR

(as of March 19, 2026, unless otherwise specified)

Solicitation of Proxies

This Management Information Circular (the Circular) is furnished in connection with the solicitation of proxies by the management of Nova Scotia Power Incorporated (the Company or NSPI) for use at the Annual Meeting of shareholders of the Company (and any adjournment thereof) (the Meeting) to be held on May 21, 2026 at the time and place and for the purposes set forth in the Notice of Meeting delivered to shareholders. While it is expected that the solicitation will be primarily by mail, proxies may be solicited personally or by telephone by the regular employees of the Company at nominal cost, or by outside parties. All costs of solicitation by management will be borne by the Company.

The contents and the sending of this Circular have been approved by the Board of Directors (defined below) of the Company.

Appointment and Revocation of Proxies

The individuals named in the accompanying form of proxy (the Proxy) are officers of the Company. **A SHAREHOLDER WISHING TO APPOINT SOME OTHER PERSON (WHO NEED NOT BE A SHAREHOLDER) TO REPRESENT THEM AT THE MEETING HAS THE RIGHT TO DO SO, EITHER BY STRIKING OUT THE NAMES OF THOSE PERSONS NAMED IN THE PROXY AND INSERTING THE DESIRED PERSON'S NAME IN THE BLANK SPACE PROVIDED IN THE PROXY OR BY COMPLETING ANOTHER FORM OF PROXY.** A proxy will not be valid unless the completed form of Proxy is received by Mark G. Everett, the Corporate Secretary of the Company, no later than 48 hours (excluding Saturdays, Sundays and holidays) before the time for holding the Meeting or any adjournment thereof, unless the Chair of the Meeting elects to exercise their discretion to accept proxies received subsequently.

A shareholder who has given a Proxy may revoke it by an instrument in writing executed by the shareholder or by their attorney authorized in writing or, where the shareholder is a corporation, by a duly authorized officer or attorney of the corporation, and delivered to Mark G. Everett, the Corporate Secretary of the Company, at any time up to and including the last business day preceding the day of the Meeting, or if adjourned, any reconvening thereof, or to the Chair of the Meeting on the day of the Meeting, prior to the commencement of the Meeting or, if adjourned, any reconvening thereof or in any other manner provided by law. A revocation of a Proxy does not affect any matter on which a vote has been taken prior to the revocation.

Voting of Proxies

The persons named in the Proxy will vote or withhold from voting the common shares (Common Shares) represented thereby in accordance with your instructions on any ballot that may be called for. If you specify a choice with respect to any matter to be acted upon, your Common Shares will be voted accordingly. The Proxy confers discretionary authority on the persons named therein with respect to:

- (i) each matter or group of matters identified therein for which a choice is not specified;
- (ii) any amendment to or variation of any matter identified therein; and
- (iii) any other matter that properly comes before the Meeting.

In respect of a matter for which a choice is not specified in the Proxy, the persons named in the Proxy will vote the Common Shares represented by the Proxy for the approval of such matter. Management is not currently aware of any other matter that could come before the Meeting.

Voting Shares and Principal Holders Thereof

Authorized Capital: 1. an unlimited number of Common Shares without nominal or par value;
 2. an unlimited number of first preferred shares, issuable in series; and
 3. an unlimited number of second preferred shares, issuable in series.

Voting Shares Issued and Outstanding: 183,517,299 Common Shares without par value

The date for determining which shareholders are entitled to receive the accompanying Notice of Meeting is March 25, 2026. This is called the "Record Date." Only shareholders of record who hold Common Shares at the close of business on the Record Date will be entitled to vote. Each Common Share owned as of the Record Date entitles the holder to one vote.

On a show of hands, every individual who is present as a shareholder or as a representative of one or more corporate shareholders, or who is holding a Proxy on behalf of a shareholder who is not present at the Meeting, will have one vote, and on a poll every shareholder present in person or represented by a Proxy and every person who is a representative of one or more corporate shareholders, will have one vote for each Common Share registered in their name or the name of the corporate shareholder(s) represented by them on the list of shareholders, which is available for inspection during normal business hours at the office of the Corporate Secretary of the Company and will be available at the Meeting.

Nova Scotia Power Incorporated – Management Information Circular 2026

To the best knowledge of the Directors and Executive Officers of the Company, the persons or companies who beneficially own, directly or indirectly or exercise control or direction over shares carrying more than 10 per cent of the voting rights attached to all outstanding Common Shares of the Company are as follows:

Name	Number of Common Shares	Percentage
Emera Incorporated Halifax, Nova Scotia	183,517,299	100%

Common Shares are the only voting shares at this time. All voting shares of the Company are beneficially owned by Emera Incorporated (Emera). Under Nova Scotia legislation that applies to the Company, no shareholder may own or control, directly or indirectly, more than 15 per cent of the outstanding voting shares that may ordinarily be cast to elect Directors other than Emera. Shareholders who are not residents of Canada may not hold, in the aggregate, more than 25 per cent of outstanding voting shares that may ordinarily be cast to elect Directors. These restrictions may be enforced by limiting non-complying shareholders' voting rights, dividend rights and transfer rights. Shareholders may be required, at any time, to furnish a statutory declaration to verify the number of shares held and/or residency in order to ensure compliance with these restrictions. For more information, see *Capital Structure* in NSPI's Annual Information Form which is available under the Company's profile on www.sedarplus.com.

BUSINESS OF THE MEETING

All resolutions placed before the Meeting must be approved by a majority of the votes cast.

- Financial Statements:** The audited financial statements of the Company for the fiscal year ended December 31, 2025 and the auditors' report thereon will be placed before the Meeting. These financial statements are available at www.sedarplus.com under NSPI's profile.
- Election of the Board of Directors:** The 9 nominees proposed for election as Directors at the Meeting are identified under *Director Nominees* in this Circular. All nominees are currently Directors of the Company and have served as Directors from the dates set out under *Director Nominees* below. Each of the 9 nominees has indicated their willingness to serve as a Director. Each Director elected at the Meeting will hold office until the next Annual Meeting of shareholders.

The persons named on the accompanying Proxy intend to vote "for" the 9 nominees unless instructed otherwise by shareholders in their Proxy.

- Appointment of Auditors:** The Board pre-approves all services to be supplied by auditors and has reviewed the performance of Ernst & Young LLP, Chartered Accountants, including its independence, relating to the audit.

The persons named on the accompanying Proxy intend to vote "for" the re-appointment of Ernst & Young LLP as auditors of the Company to hold office until the close of the next Annual Meeting of shareholders, unless a shareholder specifies their shares be withheld from voting.

Ernst & Young LLP ("EY") have been auditors of the Company since August 24, 2012. The performance and independence of the auditors is assessed annually and subject to a comprehensive review every five years. The lead audit partner with EY is rotated at least every five years, consistent with independence rules, with a minimum cooling off period of five-years.

- Auditors' Fee:** The Company is incorporated under the *Companies Act*. Shareholder approval of the authorization of Directors to establish the auditors' fee is required pursuant to the *Act*.

The aggregate fees billed by Ernst & Young LLP for the fiscal years ended December 31, 2025 and 2024, were as follows:

Service Fee	2025	2024
Audit Fees	\$1,406,500	\$565,400
Audit-related Fees	\$69,500	\$56,500
Tax Fees	\$NIL	\$NIL
All Other Fees	\$20,000	\$NIL
Total	\$1,496,000	\$621,900

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The persons named on the accompanying Proxy intend to vote "for" the authorization of Directors to establish the auditors' fee for 2026, unless a shareholder specifies their shares be voted "against" such matter.

DIRECTOR NOMINEES

The Board of Directors of the Company (the Board of Directors or the Board) presently consists of 9 Directors and it is intended that there will be 9 Directors elected for the ensuing year.

Directors are elected for a one-year term and the term of the office of each of the current Directors expires at the Meeting. The persons named below will be presented for election at the Meeting as management's nominees. Management does not contemplate that any of these nominees will be unable to serve as a Director. Each Director elected will hold office until the next Annual Meeting of the shareholders of the Company or until their successor is elected or appointed, unless their office is earlier vacated in accordance with the provisions of the *Companies Act* or the Articles of Association of the Company.

The following table states the name of each nominee for election as a Director, the jurisdiction in which they are ordinarily resident, any offices of the Company now held by such nominee, their principal occupation, and the period of time for which they have been a Director of the Company. Except as disclosed herein, no Director nominee beneficially owns, directly or indirectly, or exercises control or direction over, any Common Shares of the Company or its subsidiaries as at the Record Date. No Director nominee currently serves on the Board of Directors of another publicly traded company, except Mr. Balfour who is also a Director of Emera and Mr. Sood who is a Trustee of Crombie REIT.

Name & Municipality of Residence	Director Since	Principal Occupations During Past Five Years
Scott Balfour⁽¹⁾ Halifax, Nova Scotia Canada	2016	A Director and President and Chief Executive Officer, of Emera, a diverse energy and services company, since March 2018. Before that, Chief Operating Officer of Emera from 2016 to 2018. A Director of many Emera subsidiaries. Former Director of Martinrea International Inc. Chief Operating Officer of Emera from 2016 to 2018 and Executive Vice President and Chief Financial Officer of Emera from April 2012 to March 2016. From 1994 to 2011 Chief Financial Officer and then President of Aecon Group Inc., a Canadian publicly traded construction and infrastructure development company. Past Chair of the Ontario Energy Association.
Lee Bragg Fall River, Nova Scotia Canada	2010	Executive Chair of Eastlink, a cable and communication company, and its associated communications companies. Previously held various management positions with the Bragg Group of Companies.
Cassandra Dorrington Toronto, Ontario Canada	2021	President and Chief Executive Officer of Canadian Aboriginal and Minority Supplier Council, a not-for-profit organization, since 2010. Current Chair of Elevate International and CFIA Departmental Audit Committee (DAC), Treasurer for Federation of African-Canadian Economics (FACE) and Vice Chair for Future of Hockey Lab, and Board member for PCO's DAC. Founding member of both Supplier Diversity Advisory Committee (SDAC) and Global Supplier Diversity Alliance (GSDA). Current member of the Supplier Advisory Council for PSPC. Former board executive member for Black Business Enterprises, CPA Canada and CMA National Board, Tribe and Dalhousie University Board of Governors.
Sandra Greer Halifax, Nova Scotia Canada	2014	Former President and Chief Executive Officer of Amirix Systems Inc (now Innovasea Canada) from 2002 to 2012, a company engaged in the design, manufacture and worldwide export of acoustic marine tracking devices. Currently sits on the Board of Innovasea, based in the US, and the Board of Precision Biologic. Previously Chair of the Board of the Nova Scotia Community College as well as former member of Acadia University Board of Governors, and the NSBI Board of Directors.
Raymond Ivany⁽²⁾ Wolfville, Nova Scotia Canada	2011	Former President and Vice Chancellor of Acadia University from April 2009 to June 2017. Holds the ICD.D designation and currently sits on the Board of Directors of the Bank of Canada. Previously Chair of the Worker's Compensation Board of Nova Scotia and President and Chief Executive Officer of the Nova Scotia Community College.
Daniel P. Muldoon Halifax, Nova Scotia Canada	2025	Former Executive Vice President, Project Development and Operations Support, Emera, a diverse energy and services company, Former Executive Vice President, Major Renewable and Alternative Energy, Emera; President and Chief Operating Officer of Compressed Natural Gas (CNG), Emera; and President and Chief Operating Officer of Emera Utility Services. A past member of the executive committee for CIGRE Canada – International Council on Large Electric Systems. Previously served on both the Transmission and Distribution Councils for the Canadian Electricity Association and is a past Board Member of the Cape Breton Partnership.

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Name & Municipality of Residence	Director Since	Principal Occupations During Past Five Years
Julia Rivard Dexter Fall River, Nova Scotia Canada	2020	Co-Founder and Chief Executive Officer, Shoelace Learning Inc., an education platform. A former Olympian and previously served as Chief Executive Officer of SheepDogInc.ca. Former Vice Chair of the Board of Governors of the Nova Scotia College of Art and Design, a member of the Canadian Olympic Committee, and past member of the Nova Scotia Premier's Advisory Council. Holds both the OLY and ICD.D designations.
J. Mark Rodger Toronto, Ontario Canada	2018	Senior Counsel and Toronto Regional Co-Chair of the Energy Markets & Infrastructure Group with the law firm, Borden Ladner Gervais LLP, Toronto office. Chairman of the Board of City of Peterborough Holdings Inc. Director of the Macdonald-Laurier Institute, Ottawa. Former Director and Chair of the Board of Logistec Corporation, Montreal, Quebec.
Vivek Sood Halifax, Nova Scotia Canada	2024	President and Chief Executive Officer of NSPI since March 1, 2026. Former Executive Vice President, Related Businesses, Empire Company Limited and Sobeys Inc., and served as Executive Sponsor for Empire's Enterprise Resource Planning Initiative and Chair of Empire's Diversity, Equity, and Inclusion Council. Currently serves as a Trustee of Crombie REIT (member of the Governance and Nominating Committee and Investment Committee) and The Canadian Museum of Immigration at Pier 21 (Vice-Chair of the Board and Chair of the Audit and Risk Oversight Committee). Board Governor for Saint Mary's University (member of the Audit and Risk Committee). Honourary Lieutenant-Colonel of 1st (Halifax-Dartmouth) Field Artillery, RCA Regiment. Holds a Masters of Business Administration from Saint Mary's University, and both the CFA and ICD.D designations.

⁽¹⁾ Chair of the Board since May 2016. Mr. Balfour is President and Chief Executive Officer of Emera.

⁽²⁾ Lead Director since May 2024

Corporate Cease Trade Orders or Bankruptcies

No nominee for election as Director of the Company is, as at the date of this Circular, or was within 10 years before the date of this Circular, a Director, Chief Executive Officer (CEO) or Chief Financial Officer (CFO) of any company that:

- (a) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days, that was issued while the proposed Director was acting in the capacity as Director, CEO or CFO; or
- (b) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days, that was issued after the proposed Director ceased to be a Director, CEO or CFO and which resulted from an event that occurred while that person was acting in the capacity as Director, CEO or CFO.

No nominee for election as Director of the Company:

- (a) is, as at the date of this Circular, or has been within the 10 years before the date of this Circular, a Director or CEO of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or
- (b) has, within 10 years before the date of this Circular, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed Director.

No nominee for election as Director of the Company has been subject to:

- (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or
- (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable securityholder in deciding whether to vote for a proposed Director.

Directors' DSU Plan

Under the Directors' Deferred Share Unit and Share Purchase Plan (the "Directors' DSU Plan"), non-employee Directors may elect to receive all or any portion of their cash compensation in DSUs in lieu of that cash compensation, subject to the requirement to receive a minimum portion of their annual retainer in DSUs and subject to the Emera Director Share Ownership Guideline.

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Directors' fees are paid on a quarterly basis and, at the time of each quarterly payment, the applicable amount is converted to DSUs. The number of DSUs to be credited is determined by dividing (a) the quarterly portion of the Director's annual fee that the Director is required to receive in DSUs, together with the portion the Director elected to be paid in DSUs by (b) the fair market value of an Emera common share on the last trading day of the preceding calendar year, with fractions computed to three decimal places.

A DSU is a unit that has a value based upon the value of one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs computed by dividing: (a) the amount obtained by multiplying the amount of the dividend declared and paid per common share by the number of DSUs recorded in the Director's account on the record date for the payment of such dividend by (b) the market price of a common share as of the dividend payment date.

DSUs are only redeemable in cash after the Director's departure from the Board.

STATEMENT OF CORPORATE GOVERNANCE PRACTICES

NSPI's Board of Directors annually reviews its approach to corporate governance practices. They monitor best practices in order to enhance governance to provide stewardship to NSPI and to oversee management of the business. Set out below is a description of the corporate governance practices of the Company.

Board of Directors

All Directors nominees are independent from management, except Mr. Sood, who is President and CEO, Mr. Balfour, who is President and CEO of Emera and Mr. Muldoon, the former Executive Vice President, Project Development and Operations Support, Emera.

To be considered independent, a Director must be independent as defined under applicable Canadian securities laws and, in particular, must be free of any direct or indirect material relationship which could, in the view of the Board of Directors, be reasonably expected to interfere with the Director's independent judgment. Use of the term "independent" in relation to a Director in this Circular shall refer to the foregoing meaning of that term. None of the seven independent Directors receive remuneration from the Company other than Directors' retainers, fees or fees for service as committee members.

There were nine (9) Board meetings during 2025. At each regularly scheduled Board meeting as a matter of course, an opportunity is provided for an in-camera session at which management is not present. Additionally, since the appointment of a Lead Director in May 2019, there is also an opportunity for an in-camera session of only independent Directors of the Board at each regularly scheduled Board meeting led by the Lead Director.

Board Mandate

The Board of Directors is responsible for overseeing the management of the business of the Company. The Board is also responsible for overseeing matters of integrity, strategic planning, risk responsibility, leadership and succession, financial reporting, customer service, health, safety and environment, corporate communications and public disclosure, and corporate governance.

Position Descriptions

Chair of the Board

The Chair of the Board, Mr. Balfour, is responsible for leading the Board in fulfilling its duties effectively and efficiently. The Chair helps ensure Board meetings function effectively, provides leadership of the Board and provides advice and counsel to Directors and the President and CEO. The Chair participates in the recruitment of Directors and the assessment of their performance.

Lead Director

The Lead Director role was established by the Board in May 2019. Subsequently, the Articles of Association were amended on September 4, 2021 to establish the process for the appointment of a Lead Director. The responsibilities of the Lead Director include supporting the Board Chair in leading governance of the NSPI Board consistent with the Board's Charter; arranging at each regularly scheduled Board meeting to meet separately with only independent Directors present; reporting any concerns of independent directors to the Board Chair and, if deemed necessary by the Lead Director, to the Board; chairing meetings of the Board when the Board Chair is not in attendance; assuming the responsibilities of the Board Chair during meetings of the Board when the Board Chair declares a conflict or otherwise excuses himself from the discussion on an agenda item at a Board meeting and does not participate in a vote; and carrying out special assignments or any functions on behalf of the Board as requested by the Board or the Chair. The Lead Director also conducts of an annual evaluation of the Chair of the Board by engaging with each independent Director on the Chair's performance and to ensure there are no concerns regarding the role of the shareholder in Board governance. Mr. Ivany, was appointed Lead Director in May 2024 following the retirement of his predecessor as Lead Director, Mr. James Eisenhauer.

President and Chief Executive Officer

The roles and responsibilities of the President and CEO are contained in their employment contract and in the Articles of Association which provide that the person is the chief executive for the Company.

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Orientation and Continuing Education

The Board and management believe that for new Directors to be effective in their roles they must be knowledgeable about the Company, its strategy, strengths and challenges. As well, effectiveness is enhanced as the new Directors form a collegial working relationship with other members of the Board in order to best bring their skills and knowledge to the operation of the Board.

New Directors receive an orientation to the Company that familiarizes them with the business, investments and key personnel of the Company and allows them to effectively integrate with other Board members.

Opportunities for tours of the Company's plants and facilities occur for new and existing Directors. A reference manual is provided in advance of an orientation session for a new Director that includes the following:

- (a) recent annual and interim management's discussion and analysis (MD&A) and financials, Management Information Circular and Annual Information Form;
- (b) Board Charter;
- (c) Strategic Plan and Business Plan;
- (d) guide to the Company's management structure;
- (e) insider trading guidelines; and
- (f) Emera Code of Conduct.

Orientation and Continuing Education for Directors

The oversight function of Directors is enhanced when they are well informed about the Company's business and its industry. Management continually seeks opportunities to update, educate and inform the Directors in areas they request or that management determines are relevant to issues facing the Company.

The Board receives regular presentations from senior management updating Directors about market and industry conditions and trends that may impact the Company's existing business and influence its strategy. The Board also receives periodic specialized presentations on various matters of significance to the Company from management and the Company's outside advisors.

The Board encourages and pays for Directors to pursue education sessions provided by third parties that are directly related to the business of the Company and the performance of their duties as a Director of the Company. As such, Directors individually attended a variety of relevant educational or training sessions to enhance their effectiveness as members of the NSPI Board.

Ethical Business Conduct

The Board is committed to sustaining a culture of integrity and ethical business practices throughout the Company. The Board encourages and promotes a culture of ethical business conduct.

The Emera Code of Conduct applies to all Board members of NSPI and its affiliates, in addition to all officers and employees of NSPI. In addition, the Board of Directors has adopted the governance practice of requiring all Directors of the Company to complete annual training on the Emera Code of Conduct.

The Code of Conduct is available on the Emera's website at www.emera.com, or a copy may be obtained by contacting the Chief Human Resources Officer, Emera, P.O. Box 910, Halifax, Nova Scotia B3J 2W5.

Transactions between NSPI and related parties are monitored in several ways to determine that such transactions comply with applicable laws, regulatory rules and Emera's Code of Conduct. In particular:

- All related party transactions entered into by NSPI are governed by an Affiliate Code of Conduct approved by the Nova Scotia Energy Board. Directors, officers and employees receive annual training on the Affiliate Code of Conduct.
- Under the NSPI's Board of Directors Charter, the Board is responsible for reviewing any transaction with a value equal to or greater than \$2 million (CDN) under which it is proposed that NSPI acquire or provide to an affiliate of NSPI any goods, services, leases, asset transfers or other exchanges of value, other than energy and fuel transactions with affiliates. All such affiliate transactions require the approval of a majority of the independent Directors of the Board in order to be approved by the Board. Energy and fuel transactions with affiliates (whether greater than \$2 million (CDN) or not) are not among the affiliate transactions that require review by the Board or the approval of a majority of the independent Directors of the Board.
- Further, under the NSPI's Board of Directors Charter, if a Director becomes aware of any actual or potential conflict between their duties or obligations to NSPI and any other company of which they are a director, officer or employee, the Director will inform the Board of such conflict. If the Board determines there is a conflict, the Director will recuse them self from any deliberations by the Board on matters involving the conflict.

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- Under the Company's Articles of Association, Directors are required to declare any interest which they may have in a matter before the Board. In any matter requiring approval of the Board, a Director is prohibited by the Articles from voting in respect of the matter in which the Director is interested.
- Under Emera's Code of Conduct, Directors, officer and employees of the Company cannot own more than a 10 percent interest in, or act in the capacity of a Director, officer, partner, consultant, employee or agent for a supplier, contractor, sub-contractor, Emera customer, competitor or any other person or organization with which the Company has a similar relationship, without the express prior approval of NSPI's President, Board Chair or its Board of Directors, as the case may be. They must also seek similar approval when a company, partnership or business in which they, or a member of their family, own more than a 10 percent interest, or in which they are a Director, partner, officer, consultant, employee or agent seeks to do business with any Emera Company.

Nomination of Directors

The Company's Board of Directors is responsible for providing the Company with a list of nominees for election as Directors prior to each Annual Meeting of shareholders of the Company. The Board creates and reviews the criteria for selecting Directors, with consideration to professional skills, business experience, diversity including gender, personal qualities, and other qualifications of each Director and Director candidate, as well as the size, diversity and mix of skills of the Board overall.

Board Composition

The Company is focused on establishing and maintaining a Board with a diverse mix of experience, skills, and backgrounds. To ensure that there are a significant number of women on the Company's Board of Directors, the Company has a long-standing written corporate governance practice with respect to the required number of Directors who are female. This governance practice was amended in 2021 to increase the number of female Directors required on the Board from 25 per cent to 30 per cent. In addition, the Board also adopted the goal of having equal number of female external Directors as male external Directors.

Three of the independent external Director nominees are female and three of the independent external Director nominees are male (six of all Director nominees). Female Director nominees therefore represent 50 per cent of independent external Director nominees (33 per cent of all Director nominees). As such, the list of Director nominees meets the Company's practice with respect to female Directors.

Diversity, Equity and Inclusion

The Board of Directors has endorsed a multi-year and multi-faceted Diversity, Equity, & Inclusion plan for the Company. The plan includes metrics in several areas, including diversity and gender aspirational goals for a variety of paygrade groupings, including senior leaders. The Company believes in the benefits of diversity, equity and inclusion and among the executive positions within the executive leadership team for the Company, currently two are women, representing 40 per cent.

Ad Hoc Committees

From time to time the Board may establish ad hoc committees to assist the Board on specific matters of a temporary nature, but the Board does not currently have any standing committees.

Board and Director Performance Assessments

The Board regularly assesses its effectiveness in order to find ways to improve its performance. The Board annually reviews the process by which Director performance assessments will be conducted. The assessment process has included the use of a questionnaire and one-on-one interviews with each Directors by the Board Chair. A report on the assessment is provided to the Board of Directors at a Director-only session. To the extent any issues arising from the assessment are identified, an action plan is developed and progress is monitored by the Board.

The independent Lead Director also meets with the independent Directors to evaluate the performance of the Chair.

2025 Board and Director Performance Assessment

For the 2025 Board and Director Performance Assessment, the Chair spoke to each Director of NSPI in order to receive feedback about the effectiveness of the Board's operation. The Chair reported on the assessment to the Board at its meeting on February 11, 2026.

The Lead Director also conducted an evaluation of the Board Chair through one-on-one interviews with each independent Directors to receive feedback about the performance of the Chair and to help ensure there were no concerns with the role of the shareholder in Board governance. The Lead Director reported on the assessment at an independent Director-only session at the Board meeting on February 11, 2026.

STATEMENT OF EXECUTIVE COMPENSATION

The Emera and NSPI Boards of Directors make decisions on the compensation for NSPI's Executive Officers. The NSPI Board approves the annual compensation adjustments for NSPI's executives, excluding the President and CEO and the "Named Executive Officers" or "NEOs" as discussed below, which are approved by the Emera Board on the recommendation of Emera's Management Resources and Compensation Committee (MRCC). In addition, the NSPI Board approves the annual results of the NSPI Scorecard. The MRCC oversees the administration of

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the Long-term Incentive Program. For purposes of this *Statement of Executive Compensation*, the term “Company” may refer to NSPI, Emera or both, as applicable.

Compensation Philosophy

The purpose of the Company’s executive compensation program is to:

- attract, retain and motivate highly qualified and high-performing executives; and
- align the interests of executives with the interests of the Company’s customers and shareholders.

Programs include both short- and long-term incentive plans that are designed to reflect the Company’s pay-for-performance philosophy and to provide for a significant portion of an executive’s compensation to be at risk, while aligning the structure of programs and payouts with sound risk management and good governance principles.

Market Competitiveness

The Company’s executive compensation program is designed to generally provide total target compensation at the median or 50th percentile of compensation paid by similarly sized companies in similar industries. Pay positioning, in some specific cases, can be above or below the median based on experience, uniqueness of responsibilities and performance. “Total direct compensation” for senior management, including the named executive officers (NEOs), is comprised of base salary, target short-term incentive and target long-term incentives linked to total shareholder value.

Pay-for-Performance

A core principle of the Company’s executive compensation philosophy is that a significant portion of executive compensation must be at risk and linked to the achievement of objectives that measure whether shareholders are receiving strong value for their investment. The at-risk components include both short- and long-term incentives, which establish measurable financial, customer, asset, safety, environment, and people objectives that, if achieved, add value to the Company.

The incentive compensation plans are designed to pay larger amounts for superior performance and smaller or zero amounts if target performance is not achieved. The Company must achieve a threshold level of performance for any payment against a particular objective. Executives’ performance against those objectives is measured and rated by the President and CEO, the NSPI Board, the MRCC and the Emera Board.

Generally, the at-risk compensation component of total compensation increases in conjunction with the individual executive’s level of responsibility. Management considers many factors when developing the incentive plans, including current compensation trends, plan costs (including maximum payout values), expected value to be delivered to participants and analysis of threshold, target and stretch payouts. Both short and long-term incentive plan designs are modelled using historical and prospective performance scenarios. This stress testing provides the MRCC and NSPI Board with reasonable assurance that the plan payouts will be appropriate and aligned with shareholder and Company objectives. The Company conducts analyses every year to determine how actual payouts compare to expected payouts and whether the plan components and design require any changes.

The NSPI Board and MRCC reserve the right to exercise discretion in recommending that the Emera Board adjust compensation payouts to align with Company results, which may include refraining from paying out any amounts under the incentive compensation plans where circumstances warrant.

Governance

The MRCC and NSPI Board are responsible for reviewing the alignment of the Company’s compensation programs, including incentive pay programs, with the Company’s strategic plans, performance and risk management principles. The MRCC and NSPI Board annually review compensation for senior management of the Company.

The MRCC oversees the administration of the long-term incentive programs, including stock options, performance share units (PSUs), Restricted Share Units (RSUs), and deferred share units (DSUs) in accordance with the provisions of the respective plans.

The MRCC and NSPI Board retain the services of independent compensation advisors to assist in discharging their duties, including determining the compensation payable to the President and CEO and other senior executives.

Since 2007, the MRCC has engaged Hugessen Consulting Inc. (“Hugessen”) as its principal advisor to provide independent advice, compensation analysis and other information for compensation recommendations. Hugessen provides advice on the competitiveness and appropriateness of compensation practices and comparator groups for the Company and provides advice to the MRCC on policy recommendations made by management. As independent advisors to the MRCC, Hugessen does not provide any professional services to management. All fees paid to Hugessen are paid by Emera directly and not by the Company.

In addition to the MRCC’s compensation advisor, in 2024 Emera management engaged the services of Mercer (Canada) Ltd. (“Mercer”) and TelusHealth to assist in executive compensation matters.

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In making its decisions on the compensation program, the NSPI Board and MRCC review information and recommendations provided by Hugessen, Mercer, and TelusHealth, but all decisions remain the responsibility of the MRCC, the NSPI Board and the Emera Board.

Risk Management and Compensation

As part of the oversight responsibilities for the design and administration of the Company's executive compensation programs, the MRCC and NSPI Board identify and discuss design features or processes that may potentially represent conflicts of interest or inducements for unnecessary or excessive risk-taking by senior executives.

The MRCC and NSPI Board also regularly monitor industry trends with respect to risk management and conduct an annual risk assessment. The compensation programs and policies are designed to incorporate the Company's view on appropriate risk.

Annual Compensation Risk Assessment

In 2025, the MRCC conducted its annual compensation risk review of its executive compensation programs and policies. To assist in the review, Mercer was engaged by Emera management to evaluate their previous year's comprehensive risk assessment for any material changes over the course of the year. Mercer again concluded that the Company has risk mitigation policies in place that are aligned with market best practices and did not identify any material risks arising from the Company's compensation policies and practices.

COMPENSATION DISCUSSION AND ANALYSIS

For the purposes of compensation disclosure, the individuals disclosed in this Compensation Discussion and Analysis are the President and CEO, the CFO, and the next most highly compensated executive officer of NSPI or its subsidiaries, as defined by Canadian securities legislation (the "Named Executive Officers" or "NEOs") as set out below. R. Michael Roberts, CHRO of the company and of Emera has been identified as the next most highly compensated executive officer of NSPI as of the end of the 2025 fiscal year. Greg Blunden stepped down as Chief Financial Officer on December 1, 2025, and Jared Green assumed the role the same day.

- **Peter Gregg**, President and Chief Executive Officer of the Company from January 1, 2025 to December 31, 2025;
- **Greg Blunden**, Chief Financial Officer of the Company and of Emera from January 1, 2025 to December 1, 2025;
- **Jared Green**, Chief Financial Officer of the Company and of Emera from December 1, 2025 to December 31, 2025; and
- **R. Michael Roberts**, Chief Human Resources Officer of the Company and of Emera from January 1, 2025 to December 31, 2025.

Compensation Process

Benchmarking Data

The NSPI Board and MRCC are responsible for annually reviewing the composition and use of comparator groups and to assist in determining the compensation recommendation for the Company's senior executives which are then brought to the Emera Board for approval. The MRCC and NSPI Board undertake periodic reviews of compensation design and total compensation opportunities for the senior management team, which helps ensure the programs are current and that they fairly compare for particular roles, recognizing varying responsibility and scope of executive positions within the Company.

Management engages the services of Mercer, an independent compensation advisor, to compile market information on senior management compensation relating to base salary, short-term and long-term incentives. The MRCC also uses its independent compensation advisor, Hugessen, to assist in providing benchmarking data and advice when setting executive compensation levels and making changes to the Company's compensation programs.

A complete benchmarking review takes place at least every two years and the scope of services includes: competitive market reviews of senior executive compensation levels; review and observations of current executive compensation philosophy, policies and practices; and a review of pay and performance comparators.

2025 Compensation Decisions

To assist in determining the appropriate compensation ranges for base salaries, target short-term incentives and target long-term incentives for the senior executive team at the beginning of 2025, the NSPI Board and MRCC reviewed compensation data based on a comparator group of companies.

For the President and CEO role, the comparator group primarily consisted of companies in the Canadian utility sector that are of comparable size to NSPI, which was generally viewed as being within the range of half to twice NSPI's revenue and total asset size. The following is the comparator groups for the President and CEO:

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Pay Benchmarking Comparator Group (Applicable to President & CEO)

Utilities Industry Comparators	
Alberta Electric System Operator	FortisBC Inc.
ENMAX Corporation	Northland Power Inc.
EPCOR Utilities Inc.	Toronto Hydro Corp.
Fortis Alberta Inc.	

The Company's comparator group for the CFO and CHRO are described in the Compensation Discussion and Analysis section of Emera's Management Information Circular dated March 19, 2026, and which is available under Emera's profile on SEDAR+ at www.sedarplus.com.

The MRCC and NSPI Board continue to regularly review the composition of this comparator group to ensure they continue to reflect the Company's characteristics.

In addition to using publicly disclosed compensation data from the companies in the comparator group, for additional comfort, the MRCC and NSPI Board also considers executive compensation data from energy and services companies with similar revenues to NSPI and Emera in Mercer's Total Compensation Survey for the Energy Sector. In some cases, the MRCC and NSPI Board may consider executive compensation data from general industry companies of similar size to NSPI and Emera in Mercer's Benchmark Database Survey.

With the assistance of Hugessen and Mercer, the NSPI Board and MRCC conducted a compensation benchmarking review of the executive team for 2025 using the above companies and survey data and undertook a review of the competitiveness and appropriateness of NSPI and Emera's compensation programs. More details on the results of the review are provided in the next section.

Annual Compensation Review Process

For each executive position, a range for base salary, target short-term incentive, and target long-term incentive is established annually, using the benchmarking data along with other information on industry trends for positions of similar scope and responsibility.

Annual performance assessments are conducted on members of the senior management team, including each of the NEOs, which shape the annual salary adjustment recommendations. Based on the performance assessments and the benchmarking data, the Emera MRCC, NSPI Board and Emera Board make decisions on total target compensation for each NEO. As part of the annual compensation review process, the MRCC and Boards review emerging best practices and risk considerations.

At the end of 2024, both Management's compensation advisor, Mercer, and the MRCC's compensation advisor, Hugessen, provided the results of their benchmarking reviews, which assisted in setting the compensation levels for the NEOs for 2025.

The changes made to the compensation of the respective NEOs in 2025 are reflected in the *Table of compensation excluding compensation securities*.

Elements of Compensation

Base Salary

As noted above, the MRCC and NSPI Board are responsible for annually reviewing the composition of the compensation the Company pays its executives, including base salary. While the MRCC and NSPI Board focus on total compensation as a whole (which consists of base salary, short-term incentive and long-term incentives), base salary remains an important part of the overall compensation package the Company offers its executives.

Short-Term Incentive Program

The compensation awarded under the Short-Term Incentive Program (STIP) links a portion of an executive's compensation to the achievement of predetermined levels of performance in support of corporate and business unit objectives. These objectives are designed to focus on short-term goals (typically on an annual basis) that are intended to deliver value to customers and contribute to increased shareholder value in the longer term. Emera and NSPI have adopted the scorecard approach to translate corporate strategies into measurable incentive plan goals. Target payouts under the scorecards are generally set as a percentage of salary and are benchmarked against the median for positions with similar responsibilities in comparator companies.

The NSPI and Emera Boards approve scorecards that set forth corporate objectives and related threshold, target and stretch performance levels to be achieved each year. Short-term incentive payouts for senior management, including the NEOs, are based on scorecard results with potential payouts ranging from 0 to 200 per cent of target. Short-term incentive payouts for all NEOs are calculated based on results achieved through a corporate scorecard.

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2025 Short-Term Incentive Results

The 2025 NSPI Scorecard set out corporate objectives and related threshold, target and stretch performance levels for 2025. It was used to determine the short-term incentive payout for Mr. Gregg. No portion of any Executive's STIP, including Mr. Gregg, is included in NSPI rates.

The NSPI Scorecard is developed and recommended by NSPI management for approval by the NSPI Board at the beginning of each year. The following table shows the objectives of the NSPI Scorecard for 2025. For non-financial measures, all threshold and target level measures must be achieved to reach target level performance, and all threshold, target, and stretch measures must be achieved to reach stretch level performance.

Corporate Objective	Targets	Weighting (%)	Result	Payout (%)
Safety Achieve World Class Safety	Objectives included: Threshold: Each Supervisor / Manager will complete one and each Safety Professional will complete one unscheduled compliance check per month and document in Cority. This must include all employee crews at least once per year and 100% fixed plant coverage quarterly. Plus 90% of Senior Leadership Team (SLT) to complete one Health & Safety Engagement activity per quarter and 80% of Operations Supervisors to complete a Safety Observation at least 12 times per quarter, focused on high energy work. Target: Zero High-Energy related Serious Injuries (HSIF) (internal) plus full implementation of Emera SMS Public Safety Standard and corporate audit completed by end of Q3 with no level 1 findings. Stretch: Zero HSIF for Contractors.	20	Stretch	40
Environment Build and maintain an environmental program that manages compliance and controls risks	Objectives included: Threshold: Roll-out Emera environmental onboarding and orientation program by Q2 and have 90% of employees complete the program by year end plus completion of multiyear polychlorinated biphenyls (PCB) Phase out Action Plan per federal (Canadian Environmental Protection Agency) requirement to remove by end of 2025. Target: No Significant Environmental Incidents plus 100% completion by year end of operating company 2025 Emergency Management System (EMS) Critical Targets related to Climate Adaptation, scenario analysis, and Uncontrolled Releases as defined jointly by Emera and the operating companies. Stretch: 25% reduction of Moderate Environmental Incidents (MEI) from the 5-year (2020-2024) average, excluding Mineral Oil Dielectric Fluid (MODEF) events remediated within 30 days plus 100% completion of ALL operating company 2025 EMS Critical Targets by year end.	5	Stretch	10
People Foster high performance culture through results and the diversity of our people	Objectives included: Threshold: To promote a learning culture, 95% of team members must complete a minimum of three eLearning (or workshop) modules in the Company's Learning Management System as agreed to by their leader to support their development. Target: 75% Team members learn about Wellbeing in a workshop and put it in action by creating a personal action plan that helps support overall wellness. Achieve phishing "test click rate" results of 4% (from 4.5%) or lower at the end of the year (after removing best & worst month results). Stretch: 95% of People Leaders to be upskilled by an accredited provider on how to support team members on basic mental health challenges. Achieve phishing "test click rate" results of 3.5% or lower at the end of the year (straight measure with no removal of high/low).	10	Target	10

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Corporate Objective	Targets	Weighting (%)	Result	Payout (%)
Customer Building a reputation for customer experience	Objectives included: • Threshold: Achieve 2025 Customer First CX training plan objectives, including development of priority training content and delivery channels to target work groups plus complete 15 stakeholder engagement sessions. • Target: Deliver on priority 2025 WAM/MOS work scheduling opportunities to improve customer experience. These include enhanced status communication with customers, ongoing work force optimization & contractor visibility, modernized wiring inspection model pilot, and process redesign for complex customer development projects. • Stretch: Achieve Reliability CSAT metric of 75% plus (prorated) complete 2025 scope for EV Charging Network and Customer Demand Response projects, including: - EV Rural Charging Infrastructure site installations, - Demand response results as tracked with Time Vary Pricing (TVP) program critical peak rate recruitment plan.	10	Target	10
Asset Management Operate, maintain and invest in the assets serving our customers, fostering customer trust	Objectives included: • Threshold: Complete cost reduction initiatives (valued at \$5M) managed as developed by the Business Value Team (BVT). • Target: 5% Improvement on the average time to restore service during "Blue Sky" outage events ("Blue Sky" CAIDI <= 1.84) or 5% Improvement on the average time to restore service during "Storm" events ("Storm" CAIDI <= 7.48). • Stretch: Hydro High Priority Units DAFOR <= 7.0% (10% improvement on the 5-year average). 14 of 14 Performance Standards Achieved. and 5 Year Reliability Plan Execution - Distribution Corridor Widening (ROW) 315km - Distribution Automation Additions (12 Remote Terminal Units, 23 Distribution Protection Devices) - Distribution Build to Roadside (8km) - Distribution Conductor Upgrades (38 km)	15	Target	15
Financial ⁽¹⁾⁽²⁾⁽³⁾ Sustainable Financial Results	Objectives include: • Target: Net Earnings of \$160M at target.	30	Below Threshold	13.4
	• Target: Cash flow from Operations (CFFO) of \$239M.	10	Below Threshold	0
		100	Total: 98.4	
Less Cyber Adjustment of 10%			Final Result: 88.4	

(1) Percentage payouts, below or above target for financial measures, are interpolated on a scale between each level of performance (50 per cent for threshold, 100 per cent for target and capped at 200 per cent for stretch).

(2) For 2025, the threshold level for Net Earnings was \$144M, target level was \$160M, and stretch level was \$205M. The overall result was below threshold levels, however, the NSP Board approved an interpolated result between 0 per cent floor at \$115M and 50 per cent at \$144M.

(3) For 2025, the threshold level for CFFO was \$203M, target level was \$239M, and stretch level was \$275M. The overall result was below threshold level.

Based on the Company's achievements against the corporate objectives in the Scorecard, the NSPI Board recommended to the MRCC for approval an overall Scorecard result of 98.4 per cent of target. The result has been further adjusted and reduced by 10% for a result of 88.4 per cent of target. This adjustment is to reflect the impact of the cyber incident and applies to all NSP executives, including Mr. Gregg.

Long-Term Incentive Program

There are three primary components of long-term incentive compensation for senior management, including the NEOs: the Emera Performance Share Unit Plan (the "PSU Plan"), the Emera Restricted Share Unit Plan (The "RSU Plan") and the Emera Senior Management Stock Option Plan (the "Stock Option Plan"). The MRCC is responsible for granting PSUs, RSUs and stock options.

The number of PSUs, RSUs and stock options granted to senior management is determined after considering competitive benchmarking data and the individual's level of responsibility within the Company. Grants are calculated each year based on each executive's long-term incentive target percentage and base salary and, generally, the grant amount increases with the level of responsibility. The values of PSUs, RSUs and

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stock options increase or decrease over the term of a particular grant based on increases or decreases in Emera's common share price. No amounts paid with respect to PSUs, RSUs, and stock options are included in NSPI rates.

The MRCC takes into account previous grants and looks at a three-year history of total compensation each year before approving any new PSU, RSU and stock option grants for senior management (including the NEOs). This helps to ensure grants remain reasonable in light of market data, the performance of the Company and the performance of the individual.

In 2025, PSUs made up 50 per cent of the target long-term incentive compensatory value for NSPI's most senior executive officers, with the remaining 50 per cent divided equally between RSUs and stock options.

More details about the PSU Plan, RSU Plan and the Stock Option Plan are set forth below and are described in greater detail in the Emera's Management Information Circular dated March 19, 2026.

Performance Share Unit Plan

In addition to being affected by fluctuations in the Emera share price, the value of a PSU is dependent upon the achievement of pre-determined financial objectives that help measure the increase in value, and upon the Emera's total shareholder return (TSR) relative to its established comparator over the three-year performance period. All PSU grants must be approved by the MRCC.

Leaders are awarded PSUs based on a pre-determined dollar value target (often calculated as a percentage of base salary) and the average 10-day Emera common share price immediately preceding the effective grant date (a 50-day average is used to smooth out any short-term fluctuations in the share price). In 2025, the MRCC approved a change to the valuation methodology for outstanding units at the end of the three-year performance period, reducing the average share price calculation window from a 50-trading-day to a 10-trading-day closing price for Emera common shares. A 10-trading-day average closing share price will also be used to calculate future grants. The ultimate value of the grants is subject to the achievement of pre-determined financial objectives that are established and approved by the MRCC concurrent to the grant and measured at the completion of each three-year performance and vesting period. PSUs are settled in cash only. Actual performance against the established objectives can result in the performance factor of each PSU ranging between 0% and 200%, which directly impacts the payout value of the PSU in comparison to its grant value.

The Emera Group of Companies' long-term focus continues to be on Earnings Per Share ("EPS") growth and long-term shareholder value creation. Accordingly, the following two metrics have been used for the 2025 PSU grant, which were the same metrics and weightings used in the 2022, 2023, and 2024 PSU grants:

1. EPS growth, which continues to be a fundamental measure of the increase in profitability of the Company;
2. Relative TSR, which is a key measure of Emera's relative performance against a Canadian custom peer group.

The measures are weighted 75% and 25%, respectively.

The performance targets for the PSU awards are used for compensation purposes only and are not suitable for any other purpose. There is no assurance that any performance level will be met. The targets may also constitute forward-looking information. Forward-looking statements are based upon a number of assumptions and are subject to a number of known and unknown risks and uncertainties, any of which are beyond Emera's control, which could cause actual results to differ materially from the performance targets. Please see the cautionary statement in Emera's 2024 Annual Report respecting risks and assumptions relevant to Emera's determination of performance targets for compensation purposes.

Restricted Share Unit Plan

The RSU plan is administered similarly to the PSU plan, with the exception that there is no performance factor, nor a TSR modifier, and is only subject to a three-year vesting period.

Senior Management Stock Option Plan

Stock options are designed to deliver a percentage of the long-term incentive opportunity for senior management, including the NEOs, and are an important component of competitive executive compensation. Grants are calculated each year based on each executive's long-term incentive target percentage and base salary and, generally, the grant amount increases with the level of responsibility. All NEOs participate in the Stock Option Plan and have received stock options in 2025 as part of their long-term incentive, which the exception of Mr. Green who joined the Company after the annual grant issuance.

The exercise price for stocks options is the closing price of an Emera common share on the day immediately preceding the effective grant date. Stock options vest at a rate of 20% on each of the 1st, 2nd, 3rd, 4th and 5th anniversary of the grant. Options have a 10-year term and must be exercised before the expiry date and any unexercised options are forfeited upon expiry, unless the expiry date of the option occurs during a trading blackout period or within five business days of the end of a trading blackout period, in which case, the expiry date is automatically extended by 10 business days following the end of the blackout period.

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The maximum percentage of shares under all security-based compensation arrangements (including the Stock Option Plan and the Employee Common Share Purchase Plan) issuable to insiders of the Company at any time is 10 per cent of the issued and outstanding shares of the Company. The maximum number of shares to be optioned to any one person under the Stock Option Plan is 5 per cent of the issued and outstanding shares of the Company at the date of the grant of the option. The number of shares issued to insiders, within any one-year period, under all security-based compensation arrangements, will not exceed 10 per cent of the issued and outstanding shares of the Company.

For more information about the Senior Management Stock Option Plan, see *Senior Management Stock Option Plan* in Emera's Management Information Circular dated as of March 19, 2026 and which is available under Emera's profile on SEDAR+ at www.sedarplus.com.

COMPENSATION OF NSPI NEOs AND DIRECTORS

Recovery of NEO Compensation in Electricity Rates

No portion of the compensation or benefits paid or allocable to NEOs who are also executive officers of Emera are included in NSPI rates.

The Nova Scotia *Public Utilities Act* and the *Nova Scotia Power Incorporated Regulations* (collectively referred to as the *NSPI Regulations*) limit the type and amount of compensation paid to executives of NSPI, including the NEOs, that is recoverable in NSPI's electricity rates. Specifically, the *NSPI Regulations*: (1) prohibit any incentive or bonus pay for an executive of NSPI from being included in NSPI rates; (2) limit the recoverable portion of an executive's base salary to a level consistent with or, for the CEO, 10 per cent above, the Nova Scotia Government Senior Official Pay Plan; and (3) limit the recoverable portion of any other compensation or benefits to 13 per cent of that base salary.

The following table shows the salary, short-term incentive payouts, 2022 PSU and RSU payouts and the value of perquisites and other compensation awarded to NEOs in 2025, as well as the portion of compensation that is recovered in NSPI's electricity rates, in accordance with the *NSPI Regulations*. These compensation figures are also shown in the *Table of compensation excluding compensation securities and the Exercise of Compensation Securities by Directors and NEOs* table that follow. As shown in the table, only 27% of Mr. Gregg's total compensation as President and CEO of NSPI is included in NSPI rates. Pay associated with Mr. Gregg's Emera-wide responsibilities over Environment and Sustainability is not included in NSPI rates. As Mr. Blunden's, Mr. Green's, and Mr. Roberts' compensation is entirely paid by Emera, no amount of compensation is paid by NSPI or included in NSPI rates.

Name and position	Salary (\$) ⁽¹⁾	Recoverable in rates (\$)	Annual incentive payout (\$) ⁽²⁾	PSU/RSU payout (\$) ⁽³⁾	Value of perquisites & all other compensation (\$) ⁽⁴⁾	Recoverable in rates (\$)	Total 2025 Compensation (includ. PSU & RSU Payout)	Total amount recoverable in rates (\$)	% of Total Compensation Recoverable in Rates
Peter Gregg	539,385	321,086	476,816	240,677	71,200	41,741	1,328,078	362,828	27%
President & Chief Executive Officer									
Greg Blunden	694,627	0	337,033	693,148	149,713	0	1,874,521	0	0%
Former Chief Financial Officer, Emera Inc.									
Jared Green	35,000	0	33,964	0	3,838	0	72,802	0	0%
Chief Financial Officer, Emera Inc.									
Michael Roberts	459,385	0	445,787	249,582	66,177	0	1,220,930	0	0%
Chief Human Resources Officer, Emera Inc.									
Totals	1,728,396	321,086	1,293,600	1,183,408	290,929	41,741	4,496,332	362,828	8%

(1) A portion of Mr. Gregg's 2025 base salary earnings equaling \$38,775 were paid by Emera Inc. for Mr. Gregg's responsibilities for Emera-wide environment and sustainability. Any amount paid by Emera Inc. is not recoverable in rates.

(2) The annual incentive payout amount does not include any amount allocated to deferred share units. Mr. Blunden elected to defer 50 per cent of his 2025 annual incentive payment to DSUs. No portion of the annual incentive entitlements that were paid in cash or allocated to DSUs is recoverable in rates. Please see *Deferred Share Unit Plan* for more information on the annual incentive allocations.

(3) The PSU and RSU payments are based on the 2022 PSU and RSU grants, which had a vesting period from January 1, 2022 to December 31, 2024. The payments shown above in respect of these grants were made in early 2025. No portion of the PSU and RSU payouts is recoverable in rates.

(4) The value of perquisite and all other compensation include the compensatory change in pension, a perquisite allowance, and Company paid parking.

Compensation of Directors

With the exception of the Lead Director, all other Directors who were not employees of NSPI or its parent company, Emera, received an annual retainer of \$90,000 as compensation for their services as Directors in 2025. The compensation of NSPI's directors undergoes periodic review to help ensure it is appropriate.

The compensation for the Lead Director position on the Company's Board of Directors consisted of an all-inclusive retainer of \$135,000.

NSPI does not offer option-based awards, non-equity incentive plan participation, or participation in any pension plan to its Directors. Directors have the ability to elect to receive some or all of their cash compensation in the form of DSUs.

Total Director Compensation in 2025

Director compensation details are disclosed in the *Table of compensation excluding compensation securities* and the table of *Compensation Securities* set forth below. The NSPI President and CEO did not receive any additional compensation for his services as a Director of NSPI. Further, Mr. Balfour, Emera's President and CEO is compensated by Emera and does not receive any additional compensation as a Director of NSPI.⁽¹⁾

All Directors are reimbursed for expenses incurred for attendance at Directors' meetings, and when on NSPI's business.

⁽¹⁾ NSPI pays a corporate allocation to Emera for Director fees related to Mr. Balfour's service as a Director of NSPI in the amount of \$90,000 which amount is included in rates.

Compensation Payable to NEOs and Directors

The compensation payable to each NEO and Director for 2024 and 2025 is shown below. The table excludes compensation securities, as those are provided in the table of *Compensation securities* that follows. The compensation figures shown in the table for Mr. Blunden, Mr. Green and Mr. Roberts were paid by Emera.

Table of compensation excluding compensation securities							
Name and position	Year	Salary, consulting fee, retainer or commission (\$)	Bonus (\$) ⁽²⁾	Committee or meeting fees (\$)	Value of perquisites (\$) ⁽³⁾	Value of all other compensation (\$) ⁽⁴⁾	Total compensation (\$)
Peter Gregg⁽⁵⁾ President and Chief Executive Officer and Director	2025	539,385	476,816		23,254	47,821	1,087,276
	2024	519,904	549,120		23,254	46,100	1,101,674
Greg Blunden⁽¹⁾ Former Chief Financial Officer, Emera Inc.	2025	694,627	337,033		23,806	117,513	1,172,979
	2024	673,731	436,920		23,806	120,550	1,255,007
Jared Green⁽¹⁾ Chief Financial Officer, Emera Inc.	2025	35,000	33,964		1,738	2,100	72,802
	2024	-	-	-	-	-	-
R. Michael Roberts⁽¹⁾ Chief Human Resources Officer, Emera Inc.	2025	459,385	445,787		23,806	42,221	971,198
	2024	439,077	462,325		23,806	40,444	965,652
Scott Balfour⁽⁵⁾	2025	-	-	-	-	-	-
Board Chair	2024	-	-	-	-	-	-
Lee Bragg⁽⁶⁾	2025	45,000	-	625	-	-	45,625
Director	2024	42,500	-	-	-	-	42,500
Sandra Greer⁽⁶⁾	2025	45,000	-	-	-	-	45,000
Director	2024	42,500	-	-	-	-	42,500
Raymond Ivany⁽⁶⁾	2025	68,750	-	2,500	-	-	71,250
Lead Director	2024	115,464	-	2,500	-	-	117,964
Julia Rivard Dexter	2025	-	-	-	-	-	-
Director	2024	-	-	-	-	-	-
J. Mark Rodger	2025	-	-	-	-	-	-
Director	2024	-	-	-	-	-	-

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Name and position	Year	Salary, consulting fee, retainer or commission (\$)	Bonus (\$) ⁽²⁾	Committee or meeting fees (\$)	Value of perquisites (\$) ⁽³⁾	Value of all other compensation (\$) ⁽⁴⁾	Total compensation (\$)
Cassandra Dorrington	2025	-	-	-	-	-	-
Director	2024	-	-	-	-	-	-
Vivek Sood	2025	-	-	-	-	-	-
Director	2024	12,541	-	-	-	-	12,541
Daniel Mudoon	2025	45,370	-	-	-	-	45,370
Director	2024	-	-	-	-	-	-

⁽¹⁾ In 2025, Mr. Blunden, Mr. Green and Mr. Roberts participated in the Emera Corporate Scorecard.

⁽²⁾ The bonus figures provided reflect the short-term incentive paid to the executive in cash. For 2025, the payouts were based on the NSPI Scorecard result of 88.4 per cent and the Emera Scorecard result of 121.3 per cent. For 2024, the payouts were based on NSPI Scorecard results of 132 per cent and Emera Scorecard results of 122.4 per cent. The Short-Term Incentive Plan and the 2025 NSPI Scorecard results are described in greater detail in *Short-Term Incentive Program*. The figures shown reflect amounts earned in the 2025 performance year and paid in 2026, and do not include any amounts that have been deferred to DSUs. For the 2025 performance year, Mr. Blunden elected to receive 50 percent in DSUs. Please see *Deferred Share Unit Plan* for more information on the annual incentive allocations.

⁽³⁾ The 'Value of perquisites' includes but is not limited to amount paid to the executive for car allowance, tax preparation, and relocation as applicable.

⁽⁴⁾ The 'Value of all other compensation' figures for NEOs include changes in the accrued obligations of the NEOs' pension entitlements.

⁽⁵⁾ Mr. Gregg and Mr. Balfour did not receive any compensation in 2025 for their service as Directors of NSPI. NSPI pays a corporate allocation to Emera in the amount of \$90,000 for Director fees related to Mr. Balfour's service as a Director of NSPI which amount is included in rates.

⁽⁶⁾ Mr. Janega, Mr. Bragg, Ms. Greer, and Mr. Ivany elected to receive 50 per cent of their flat fee as DSUs and the remaining 50 per cent as cash.

The following table shows the compensation securities granted to each NEO and Director in 2025:

Compensation Securities								
Name and position	Type of compensation security	Description	Number of compensation securities, number of underlying securities, and percentage class ⁽¹⁾		Date of issue or grant	Issue, conversion or exercise price (\$)	Closing price of security or underlying security on date of grant (\$)	Expiry Date
Peter Gregg President and Chief Executive Officer and Director	Performance Share Units ⁽²⁾	2025 Grant	9,191	0.00%	1-Jan-25	52.88	53.73	N/A
	Restricted Share Units	2025 Grant	4,598	0.00%	1-Jan-25	52.88	53.73	N/A
	Stock Options ⁽³⁾	2025 Grant	42,600	1.03%	25-Feb-25	57.00	57.28	24-Feb-2035
	Deferred Share Units ⁽⁴⁾	STIP allocation	-	0.00%	1-Jan-25	52.88	53.73	N/A
Greg Blunden Former Chief Financial Officer, Emera Inc.	Performance Share Units ⁽²⁾	2025 Grant	14,462	0.00%	1-Jan-25	52.88	53.73	N/A
	Restricted Share Units	2025 Grant	7,230	0.00%	1-Jan-25	52.88	53.73	N/A
	Stock Options ⁽³⁾	2025 Grant	67,100	1.63%	25-Feb-25	57.00	57.28	24-Feb-2035
	Deferred Share Units ⁽⁴⁾	STIP allocation	6,250	0.00%	1-Jan-25	52.88	53.73	N/A
Michael Roberts Chief Human Resources Officer, Emera Inc.	Performance Share Units ⁽²⁾	2025 Grant	5,437	0.00%	1-Jan-25	52.88	53.73	N/A
	Restricted Share Units	2025 Grant	2,720	0.00%	1-Jan-25	52.88	53.73	N/A
	Stock Options ⁽³⁾	2025 Grant	25,200	0.61%	25-Feb-25	57.00	57.28	24-Feb-2035
	Deferred Share Units ⁽⁴⁾	STIP allocation	-	0.00%	1-Jan-25	52.88	53.73	N/A
Scott Balfour ⁽⁶⁾ Board Chair	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Richard Janega Director	Deferred Share	Q1 Fees	32	N/A	31-Mar-25	53.73	53.73	N/A

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Name and position	Type of compensation security	Description	Number of compensation securities, number of underlying securities, and percentage class ⁽¹⁾		Date of issue or grant	Issue, conversion or exercise price (\$)	Closing price of security or underlying security on date of grant (\$)	Expiry Date
Lee Bragg ⁽⁷⁾ Director	Deferred Share	Q1 Fees	207	N/A	31-Mar-25	53.73	53.73	N/A
	Units ⁽⁵⁾	Q2 Fees	220	N/A	30-Jun-25	53.73	53.73	N/A
		Q3 Fees	211	N/A	30-Sep-25	53.73	53.73	N/A
		Q4 Fees	211	N/A	31-Dec-25	53.73	53.73	N/A
Cassandra Dorrington ⁽⁷⁾ Director	Deferred Share	Q1 Fees	413	N/A	31-Mar-25	53.73	53.73	N/A
	Units ⁽⁵⁾	Q2 Fees	441	N/A	30-Jun-25	53.73	53.73	N/A
		Q3 Fees	422	N/A	30-Sep-25	53.73	53.73	N/A
		Q4 Fees	422	N/A	31-Dec-25	53.73	53.73	N/A
Sandra Greer Director	Deferred Share	Q1 Fees	207	N/A	31-Mar-25	53.73	53.73	N/A
	Units ⁽⁵⁾	Q2 Fees	209	N/A	30-Jun-25	53.73	53.73	N/A
		Q3 Fees	211	N/A	30-Sep-25	53.73	53.73	N/A
		Q4 Fees	211	N/A	31-Dec-25	53.73	53.73	N/A
Raymond Ivany ⁽⁷⁾ Director	Deferred Share	Q1 Fees	321	N/A	31-Mar-25	53.73	53.73	N/A
	Units ⁽⁵⁾	Q2 Fees	325	N/A	30-Jun-25	53.73	53.73	N/A
		Q3 Fees	317	N/A	30-Sep-25	53.73	53.73	N/A
		Q4 Fees	363	N/A	31-Dec-25	53.73	53.73	N/A
Mark Rodger ⁽⁷⁾ Director	Deferred Share	Q1 Fees	413	N/A	31-Mar-25	53.73	53.73	N/A
	Units ⁽⁵⁾	Q2 Fees	441	N/A	30-Jun-25	53.73	53.73	N/A
		Q3 Fees	422	N/A	30-Sep-25	53.73	53.73	N/A
		Q4 Fees	422	N/A	31-Dec-25	53.73	53.73	N/A
Julia Rivard Dexter ⁽⁷⁾ Director	Deferred Share	Q1 Fees	436	N/A	31-Mar-25	53.73	53.73	N/A
	Units ⁽⁵⁾	Q2 Fees	441	N/A	30-Jun-25	53.73	53.73	N/A
		Q3 Fees	422	N/A	30-Sep-25	53.73	53.73	N/A
		Q4 Fees	492	N/A	31-Dec-25	53.73	53.73	N/A
Vivek Sood ⁽⁷⁾ Director	Deferred Share	Q1 Fees	436	N/A	31-Mar-25	53.73	53.73	N/A
	Units ⁽⁵⁾	Q2 Fees	441	N/A	30-Jun-25	53.73	53.73	N/A
		Q3 Fees	422	N/A	30-Sep-25	53.73	53.73	N/A
		Q4 Fees	492	N/A	31-Dec-25	53.73	53.73	N/A

⁽¹⁾ Each PSU, RSU, stock option and DSU represent one underlying Emera common share. PSUs, RSUs and DSUs granted to executives are settled in cash under the terms of the PSU Plan, the RSU Plan and the DSU Plan applicable to executives. DSUs granted to Directors can only be settled in cash under the terms of the Directors' DSU Plan. PSUs and RSUs vest over a three-year period and Stock Options vest in even tranches over five years. DSUs are deemed to be vested at the time of grant but are only redeemable after departure from the Company. For PSUs, RSUs and DSUs awarded to executives, the percentage of class is calculated by dividing the applicable units by the weighted average outstanding Emera common shares as of December 31, 2025 (299,165,827). For stock options, the percentage of class is calculated by dividing the applicable options by the number of outstanding options as at December 31, 2025 (4,116,481).

⁽²⁾ The grant value of PSUs and RSUs granted in 2025 was based on the average 50 trading-day closing share price up to December 31, 2024 (\$52.88). The 50-day share price average is used for PSU and RSU grants to smooth out any short-term fluctuations in share price preceding the grant date. The value of PSUs on payout is subject to the achievement of specific performance objectives over the three-year performance period from January 1, 2025 to December 31, 2027. If those objectives are not met, payouts may be less than the initial value of the grant noted above (or there may not be any payout at all) and if performance objectives are exceeded, the payout may be higher than the amount noted above. The closing price at year-end is based on the closing price of Emera common shares as at December 31, 2024; however, the share price used to calculate the PSU and RSU payouts will be based on the average 10 trading-day closing share price at the end of the performance period. The issue price for dividends is based on the average 5 trading-day closing share price immediately preceding the dividend payment date. For more information on PSUs and RSUs, please see *Performance Share Unit Plan* and *Restricted Share Unit Plan*.

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- (3) The value of the stock options granted to the NEOs in 2025 was determined to be equal to 10 per cent of the February 24, 2025 closing share price of \$57.00 or \$5.70 per option. The Company has adopted a floor value ratio of 10 per cent; if the Black-Scholes methodology leads to a value ratio that is less than 10 per cent, the floor of 10 per cent will apply. The Black-Scholes valuation for 2025 resulted in a value ratio of 7.4 per cent to 11.1 per cent, using an estimated dividend yield of 5.4 per cent, and a risk-free interest rate of 3.29 per cent. The range was dependent on the number of months over which the volatility calculation was measured, from 12 to 120 months, which led to volatility measurements from 16.2 per cent to 21.3 per cent. Because the Black-Scholes valuation was below 10 per cent, the floor of 10 per cent was used to value stock options in 2025. For more information on stock options, please see *Senior Management Stock Option Plan*.
- (4) The grant value of DSUs granted in 2025 was based on the average 50 trading-day closing share price up to December 31, 2024 (\$52.88). The 50-day share price average is used for DSU grants to smooth out any short-term fluctuations in share price preceding the grant date. The closing price at year-end is based on the closing price of Emera common shares as of December 31, 2024; however, the share price used to calculate the DSU payout will be based on the average 10 trading-day closing share price immediately preceding the payout date, which cannot occur until the executive leaves the employment of Emera or its affiliates. The issue price for dividends is based on the average 5 trading-day closing share price immediately preceding the dividend payment date. For more information on DSUs, please see *Deferred Share Unit Plan*.
- (5) The grant value of DSUs granted to Directors in 2025 was based on the closing price of Emera common shares on December 31, 2024 (\$53.73). Directors cannot settle DSUs until they leave the Board.
- (6) Mr. Balfour, Emera's President, is compensated by Emera and did not receive any additional compensation in 2025 as a Director of NSPI.
- (7) Mr. Bragg, Ms. Dorrington and Mr. Roger attended one ad hoc meeting and received \$1,250. Ms. Rivard-Dexter and Mr. Sood attended three ad hoc meetings and received \$1,250 for each meeting. Mr. Ivany attended four ad hoc meetings and received \$1,250 for each meeting.
- (8) As of December 31, 2025, the total holdings of compensation securities and underlying securities of each NEO and Director, including all restricted share units, performance share units and deferred share units, and all dividend equivalents on each of them, and stock options, is as follows: Mr. Gregg held 218,156 securities, Mr. Blunden held 571,695 securities, Mr. Roberts held 199,170 securities, Mr. Janega held 174,803, Mr. Bragg held 26,492 securities, Ms. Dorrington held 7,532 securities, Ms. Greer held 22,671 securities, Mr. Ivany held 39,096 securities, Mr. Rodger held 10,799 securities, Ms. Rivard Dexter held 10,458 securities, and Mr. Sood held 2,356 securities.

The following table shows the compensation securities exercised by Directors and NEOs in 2025:

Exercise of Compensation Securities by Directors and NEOs							
Name and position	Type of compensation security	Number of underlying securities exercised	Exercise price per security (\$)	Date of exercise	Closing price per security on date of exercise (\$)	Difference between exercise price and closing price on date of exercise (\$)	Total value on exercise date (\$)
Peter Gregg President and Chief Executive Officer and Director	Performance Share Units ⁽¹⁾	2,310	52.88	1-Jan-25	53.73	0.85	122,157
	Restricted Share Units ⁽¹⁾	2,241	52.88	1-Jan-25	53.73	0.85	118,520
Greg Blunden Chief Financial Officer, Emera Inc.	Performance Share Units ⁽¹⁾	6,643	52.88	1-Jan-25	53.73	0.85	351,265
	Restricted Share Units ⁽¹⁾	6,465	52.88	1-Jan-25	53.73	0.85	341,883
Michael Roberts Chief Human Resources Officer, Emera Inc.	Performance Share Units ⁽¹⁾	2,391	52.88	1-Jan-25	53.73	0.85	126,420
	Restricted Share Units ⁽¹⁾	2,329	52.88	1-Jan-25	53.73	0.85	123,162

- (1) The value of PSUs and RSUs exercised in 2025 is based on the 2022 PSU and RSU grants, which both had a three-year vesting period from January 1, 2022 to December 31, 2024. The 2022 PSU and RSU grants were deemed to be paid out on January 1, 2025. The payout is calculated based on the original grant with accumulated dividends and multiplied by the average closing share price for the last 50 trading days of 2024 (\$52.88). The 50-day share price average is used to smooth out any short-term fluctuations in share price preceding the payout date. The 2022 PSU grant was also subject to a performance factor based on Emera's EPS growth and Emera's total shareholder return relative to a custom Canadian peer group. Units shown above have been rounded however, the value amount is calculated based on the actual number of units, including fractional units. The overall performance factor result was 0.514, which was applied to the 2022 PSU grant payouts. Please see *Performance Share Unit Plan* for more details.

No portion of the total value realized by the NEOs through the payout of securities was included in rates.

Pension Plan Benefits

The Company has adopted a pension governance framework that sets out the structure and processes for overseeing the management and administration of all pension plans sponsored or administered by Emera and its affiliates to ensure that the liabilities associated with such pension plans are being appropriately managed.

The NEOs are members of the Canadian corporate pension plan ("Pension Plan") and participate on either a defined benefit basis or a defined contribution basis. For 2025, one NEO participated in the defined benefit component of the Pension Plan and four NEOs participated in the defined contribution component of the Pension Plan.

Defined Benefit

The following table shows years of credited service, estimated pension amounts and changes to accrued obligations from January 1, 2025 to December 31, 2025 for the NEOs who participated in the Pension Plan on a defined benefit basis.

Annual benefits payable							
Name	Number of years credited service (#)	At year-end (\$) ⁽¹⁾	At age 65 (\$) ⁽¹⁾	Accrued obligation at the start of the year (\$) ⁽¹⁾	Compensatory change (\$) ⁽²⁾	Non-compensatory change (\$) ⁽²⁾	Closing present value of defined benefit obligation (\$) ⁽³⁾
Greg Blunden ⁽⁴⁾	1.3	22,610	22,610	698,593	14,663	25,481	738,737

- (1) All NEOs were eligible for an immediate pension at year-end. The amount shown is the accrued pension starting at the NEO's unreduced retirement date if the NEO terminated employment at December 31, 2025.
- (2) The compensatory and non-compensatory changes are described in more detail below.
- (3) The accrued pension obligation is calculated following the method prescribed under USGAAP (section 715 of the standards of the Financial Accounting Standards Board) and by the Canadian Institute of Chartered Accountants and is based on management's best estimate of future events that affect the cost of pensions, including assumptions about future salary adjustments and short-term incentive awards.
- (4) Mr. Blunden accrues future benefits under the defined contribution component of the Pension Plan and has frozen service under the defined benefit component of the Pension Plan.

The accrued obligation of a pension entitlement is the present value of the expected future annual benefits payable taking into account service accrued to date and the expected salaries used to determine the annual benefit payable at retirement. Each year, the value of the accrued obligation changes as a result of compensatory changes and non-compensatory changes, which are shown in the table above.

Compensatory changes are caused by changes in the annual benefit payable and result primarily from three factors:

- (i) new accrued service (the employer current service cost);
- (ii) the impact of salary increases greater than expected on past benefits (estimated increases are already built into the accrued benefit obligation); and
- (iii) plan changes impacting, for example, accrued service or when benefits are payable. There were no Pension Plan changes that materially affected the above figures in 2025.

Non-compensatory changes are caused by interest on the accrued obligation and current service cost, employee required contributions and changes in the assumptions used to calculate the present value of the future annual benefit payment stream. These assumptions include the mortality table, salary scale, retirement assumption and the inflation assumption used for calculating indexing and the discount rate. The non-compensatory changes in 2025 were driven largely by changes in actuarial assumptions as well as interest on the accrued obligation and current service cost. The assumption changes from December 31, 2024 to December 31, 2025 were a change in the discount rate from 4.64 per cent to 4.90 per cent for the Pension Plan, 4.13 per cent to 4.08 per cent for the retirement award, and 4.63 per cent to 4.86 per cent for the supplemental employee retirement plan ("Supplementary Retirement Plan"). The net effect of the assumption changes is a decrease in obligations.

The defined benefit component of the Pension Plan entitles members to pension benefits based on two per cent of the average of the member's five highest years of pensionable earnings, multiplied by each year of credited service to a maximum of 35 years credited service. For the NEOs, pensionable earnings include base salary plus up to 50 per cent of their target short-term incentive. Upon a member reaching age 65, pension benefits under the Pension Plan are reduced by an amount approximately equal to the amount payable under the Canada Pension Plan. For members who retire from active service, the pension is payable on an unreduced basis upon the earlier of age 60 or age 55, provided that age and years of service add to at least 85. For members who joined the Pension Plan on or after July 1, 2004, the age 60 unreduced retirement age condition is replaced by age 62 with 15 years of service. A member may also retire on a reduced formula if the member has attained age 55, but does not qualify for an unreduced pension. Spousal benefits are paid on the death of a member at the rate of 60 per cent of regular pension benefits. Pensions are indexed to the consumer price index, subject to certain limits.

For 2025, members of the defined benefit component of the plan contributed 7.4 per cent of eligible earnings up to the year's maximum pensionable earnings ("YMPE") under the Canada Pension Plan, and 9.5 per cent of earnings between the YMPE and the amount on which pension benefits may be earned under a registered pension plan as permitted by the Income Tax Act (Canada).

Due to Canada Revenue Agency limitations on the maximum pension benefit that may be paid under the Pension Plan, a portion of the pension the NEOs earned after January 1, 1992 is provided under the terms of the Supplementary Retirement Plan, which is unfunded but secured by a letter of credit deposited in a retirement compensation trust. The Supplementary Retirement Plan is non-contributory. The Supplementary Retirement Plan generally mirrors the terms of the Pension Plan, with the exception that benefits earned on service in the SERP after December 31, 2017 are not indexed on retirement. The Company does not grant additional years of credited service to NEOs under the Pension Plan or Supplementary Retirement Plan.

The defined benefit component of the Pension Plan was closed to new non-union employees hired after January 8, 2013 and to new union employees hired after October 31, 2014. The defined benefit component of the Supplementary Retirement Plan was closed to new entrants as of December 31, 2017. Any employees who become eligible to participate in the Supplementary Retirement Plan after December 31, 2017 will participate in the defined contribution component.

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The compensatory and non-compensatory change figures for Mr. Blunden include the increase in value of a potential retirement award. Certain employees of the Company hired before August 1, 2007 are eligible for a retirement award if they continue working with the Company until their unreduced retirement date. The retirement award is calculated by multiplying the employee's weekly base salary immediately preceding retirement by the employee's number of years of service at retirement, to a maximum of 26 weeks of salary, and is payable as a lump sum on retirement. If the employee terminates employment with the Company prior to his or her unreduced retirement date, no retirement award is payable. Mr. Blunden will be entitled to the retirement award if he continues working for an Emera company until his unreduced retirement date.

Defined Contribution

The following table shows the changes to accumulated value from January 1, 2025 to December 31, 2025 for the NEOs who participated in the Pension Plan on a defined contribution basis.

Name	Accumulated value at start of year (\$)	Compensatory change (\$) ⁽¹⁾	Non- compensatory change (\$) ⁽²⁾	Accumulated value at end of year (\$)
Greg Blunden ⁽³⁾	2,055,819	98,850	319,048	2,473,718
Peter Gregg	270,714	47,821	45,081	363,616
Michael Roberts	541,594	38,221	70,105	649,920
Jared Green ⁽⁴⁾	—	2,100	2,097	4,197

(1) The compensatory change is the value of Company contributions made based on the defined contribution component of the Pension Plan.

(2) The non-compensatory change is the value of employee contributions to the Pension Plan, along with investment earnings.

(3) Mr. Blunden accrues future benefits under the defined contribution component of the Pension Plan and has frozen service under the defined benefit component of the Pension Plan.

(4) Mr. Green joined the Company as at December 1, 2025.

Under the defined contribution component of the Pension Plan, the Company contributes a base amount of three per cent of the participant's eligible earnings into the participant's account each pay period. Plan participants can also make contributions of up to six per cent of their eligible earnings to the defined contribution component, with the Company matching half of these contributions. Accordingly, the maximum Company contribution to each participant's defined contribution account, factoring in the base amount and the matching contribution, is six per cent of the participant's eligible earnings. Canada Revenue Agency limits apply to limit the amount of contributions that can be made under the defined contribution component and, as with the defined benefit component, a portion of the pension a NEO earns in the defined contribution component may be provided under the terms of a Supplementary Retirement Plan.

Mr. Blunden, Mr. Gregg, and Mr. Roberts participated in the defined contribution component of the Pension Plan in 2025. They and the Company each contributed six per cent of their base salary into the Pension Plan up to the total amount permitted under the Income Tax Act (Canada), which equated to \$16,905 each in 2025. In addition, the Company maintains an account for any contributions which would be made in the absence of the Income Tax Act (Canada) limits, through the Supplementary Retirement Plan. For 2025, the additional Company contribution for Mr. Blunden was \$81,945, for Mr. Gregg was \$30,916 and for Mr. Roberts was \$21,316. Mr. Green participated in the defined contribution component of the Pension Plan for December 2025. He and the company contributed six per cent of his base salary into the Pension Plan for that month, \$2,100 each. Where Mr. Green contributed under the amount permitted under the Income Tax Act (Canada) for 2025, the Company did not make any additional contributions through the Supplementary Retirement Plan.

Upon ending active employment with the Company at any age between 55 and 65, plan participants in the defined contribution component of the Pension Plan may start receiving retirement income through the purchase of a life annuity or by converting their account to a life income fund.

The defined contribution component of the Pension Plan is administered on behalf of the Company by a major Canadian insurance company, which acts in accordance with the provisions of the defined contribution component of the Pension Plan, the Income Tax Act (Canada) and the Nova Scotia Pension Benefits Act.

Deferred Share Unit Plan

The Deferred Share Unit (DSU) Plan is another component of Emera's long-term incentive program that is made available to senior leaders of the Company. A DSU is a notional share unit that is based on the value of an Emera common share – the value of a DSU changes directly in correlation to an Emera share and earns dividend equivalents in the form of additional DSUs. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs based on the dividend paid on an equivalent number of Emera common shares. DSUs are not paid out until such time as the participant is no longer employed by the Company or any of its affiliates. When redeemed, the value of a participant's DSUs is equivalent to the fair market value of an equal number of common shares of the Company.

The DSU Plan is intended to facilitate achievement of share ownership guidelines without diluting the shareholder base. Prior to the start of each performance year, each plan participant may elect to defer some, or all of the short-term incentive payout associated with that performance year in the form of DSUs. When the short-term incentive is paid to the NEOs, the portion elected is allocated to DSUs rather than paid in cash. Since DSUs are principally an income deferral mechanism, there are no performance metrics attributable to DSUs.

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Following a participant's departure from the Company and on a date selected by the participant not later than December 15 of the next calendar year after departure, the value of the participant's DSUs is calculated by multiplying the number of DSUs in the participant's account by the average closing Emera common share price for the 10 trading days preceding the payout date (the 10-day average is used to smooth out any short-term price fluctuations).

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or the achievement of certain corporate objectives.

DSU Plan Allocations

The table below identifies how much each NEO elected to allocate their short-term incentive to DSUs for 2024 and 2025:

Name	2025		2024	
	Percentage of annual incentive allocated to deferred share units (%)	Dollar amount of annual incentive allocated to deferred share units (\$) ⁽¹⁾	Percentage of annual incentive allocated to deferred share units (%)	Dollar amount of annual incentive allocated to deferred share units (\$) ⁽¹⁾
Peter Gregg	0	0	0	0
Greg Blunden	50	337,033	50	330,480
Michael Roberts	0	0	0	0

⁽¹⁾ The DSU allocations are rounded to the nearest whole unit, so the value of DSUs may vary slightly from the amount of short-term incentive payout allocated.

Mr. Green was not employed at the time of making DSU allocation elections for the 2025 short-term incentive.

Employee Common Share Purchase Plan

Executives are also eligible to participate in the Employee Common Share Purchase Plan, which allows employees of Emera and its affiliates to purchase Emera common shares through regular payroll deductions or lump-sum payments. Participants can contribute up to \$20,000 CAD/\$15,000 USD per year, and Emera will match 20 per cent on employee contributions up to the contribution limit. The purchase price of the common shares under the Plan is the average of the daily high and low board lot trading price on the TSX for the five trading days prior to the purchase date. At Emera's option, shares may be purchased instead on the market at prevailing market prices. All common shares purchased under the Plan are immediately vested. Executives participate on the same terms as all other eligible employees.

Termination and Change of Control Benefits

The following table provides the estimated amounts of incremental payments, payables and benefits to which Peter Gregg would be entitled based on differing departure scenarios—resignation, termination for cause, termination without cause, separation from the Company in circumstances of a change of control, and retirement, assuming the triggering event took place on December 31, 2025. NSPI has no obligations in respect of a termination of any other NEO.

Name	Departure scenario ⁽¹⁾	Cash severance (\$)	Short-term incentive (\$)	Performance share units (\$) ⁽²⁾	Restricted share units (\$) ⁽²⁾	Stock options (\$) ⁽³⁾	Continuation of benefits (present value) (\$) ⁽⁴⁾	Total (\$)
Peter Gregg	Resignation	-	-	-	-	-	-	-
	Termination for cause	-	-	-	-	-	-	-
	Termination without cause	810,000	648,000	-	-	-	7,968	1,465,968
	Change of control	540,000	432,000	1,329,851	665,287	1,816,563	7,968	4,791,669
	Retirement	-	-	-	-	-	-	-

⁽¹⁾ Please see the following table for a description of the entitlements of Mr. Gregg under the various departure scenarios.

⁽²⁾ The value of PSUs and RSUs in the above table was determined using the 10-day average closing share price of an Emera common share at the end of 2025, which was \$67.02.

⁽³⁾ The value of stock options in the above table was determined using the closing share price on December 31, 2025, which was \$67.64.

⁽⁴⁾ Continuation of benefits may reflect amounts for health and dental benefits and insurance benefits, pursuant to the terms of the NEOs' employment contracts, as applicable.

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The following is a summary of the entitlements on departure afforded to Peter Gregg under his employment contract or the applicable plans as of December 31, 2025:

Peter Gregg	
Resignation	All unvested PSUs, RSUs and stock options are forfeited.
Terminated for cause	All unvested PSUs, RSUs and stock options are forfeited.
Terminated without cause	Entitled to a lump sum equal to 18 months' compensation based upon annual salary and short-term incentive at target. Health, dental and other such benefits will be continued for up to 12 months. Unvested PSUs and RSUs are prorated to the date of termination and paid out at the end of the respective performance period, subject to the achievement of the applicable performance criteria. Unvested stock options are forfeited.
Change of control	If there is a change of control of the ownership of the Company, such that any one party acquires 50 per cent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Mr. Gregg may elect, within three months following such substantial reduction in responsibilities or scope of authority, to terminate employment and receive 12 months' compensation based upon annual salary and short-term incentive at target. Health, dental and other such benefits will be continued for up to 12 months. Unvested PSUs and RSUs are prorated to the date of termination and paid out assuming a performance factor of 1.0. Should the executive terminate their employment for "good reason" ⁽¹⁾ as defined below and in the Senior Management Stock Option Plan, unvested stock options that were granted prior to the change of control are deemed to vest on the termination date and must be exercised by the earlier of (a) six months from the termination date; and (b) 10 years from the original grant date.
Retirement	Mr. Gregg became eligible for retirement on June 7, 2022. Information regarding pension entitlement is contained in Pension Plan Benefits. If Mr. Gregg stays employed and qualifies for early retirement under the PSU/RSU plans, his outstanding PSUs and RSUs will continue to vest normally, with payouts prorated based on service up to his retirement date. Under the Stock Option Plan, vested options remain exercisable until expiry, while unvested options are forfeited. If he stays employed and qualifies for normal retirement, his PSUs and RSUs will continue to vest normally and remain eligible for full payout. Under the Stock Option Plan, vested options remain exercisable until expiry, and unvested options continue to vest and remain exercisable until expiry.

(1) "Good Reason" is defined in the Senior Management Stock Option Plan as:

- a. a material diminution in the Optionee's base salary or a material reduction in aggregate annual target total direct compensation
- b. a material diminution in the Optionee's authority, duties, or responsibilities by the Company or its Affiliates, as applicable; or
- c. changing the location to which the Optionee regularly reports to perform the Optionee's duties to the Company or Affiliate, as applicable by more than 50 kilometers.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

Emera has established equity compensation plans which apply to the Company. See *Statement of Executive Compensation* in Emera's Management Information Circular dated as of March 19, 2026, and which is available under Emera's profile on SEDAR+ at www.sedarplus.com.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

The Company does not have a program that allows for the provision of loans to Directors or Officers, and the Company is not intending to initiate such a program. In addition, there is no program to allow loans or indebtedness under any share purchase program. As of the date of this Circular, there was no indebtedness of the Directors to the Company or any of its subsidiaries. As of the date of this Circular, except for routine indebtedness, there is no indebtedness of Executive Officers and other employees to the Company or any of its subsidiaries.¹

MATERIAL TRANSACTIONS

Since the commencement of the most recently completed financial year, insiders of the Company and its affiliates, including Directors, executive officers, proposed Director nominees or their associates or corporations they controlled, did not have any material interest, direct or indirect, in any transaction or in any proposed transaction that has materially affected or will materially affect the Company or any of its subsidiaries.

MANAGEMENT CONTRACTS

There are no functions of management that are performed by a person or company other than the Directors, executive officers or other employees of the Company or its subsidiaries.

OTHER MATTERS

Management of the Company knows of no matters to come before the Meeting other than those referred to in the Notice of Meeting accompanying this Circular. However, if any other matters properly come before the Meeting, it is the intention of the persons named in the Proxy accompanying this Circular to vote the same in accordance with their best judgment of such matters.

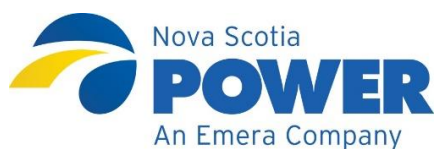
ADDITIONAL INFORMATION

Additional information relating to the Company is available under the Company's profile on SEDAR+ at www.sedarplus.com. Shareholders may contact Mark G. Everett, the Company's Corporate Secretary, to request copies of the Company's financial statements and MD&A for the fiscal year ended December 31, 2025. Financial information is provided in the Company's annual financial statements and MD&A for the fiscal year ended December 31, 2025.

APPROVAL OF THIS CIRCULAR

The Board of Directors has approved the contents of this Circular and has authorized it to be sent to the shareholders of the Company.

¹ "Routine indebtedness" includes: (i) loans made on terms no more favourable than loans to employees generally, for which the amount remaining unpaid does not exceed \$50,000; (ii) loans to full-time employees, fully secured against their residence and not exceeding their annual salary; and (iii) loans for purchases on usual trade terms, or for ordinary travel or expense advances, or similar reasons, with repayment arrangements in accordance with usual commercial practice.



Nova Scotia Power Incorporated

2025 Annual Information Form

For the year ended December 31, 2025

February 23, 2026

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2025. Amounts are expressed in Canadian dollars unless otherwise indicated. All financial information presented in millions of Canadian dollars is rounded to the nearest million unless otherwise stated. Unless otherwise indicated, all financial information is presented in accordance with USGAAP.

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

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

This AIF, including the documents incorporated herein by reference, contains "forward-looking information" and "forward-looking statements" within the meaning of applicable securities laws (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecast", "intends", "may", "might", "plans", "projects", "schedule", "should", "targets", "will", "would", and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this AIF, including the documents incorporated herein by reference, includes statements which reflect the current view of NSPI's management with respect to, NSPI's objectives, plans, financial and operating performance, carbon dioxide emissions reduction goals, information technology systems restoration, insurance recoveries, and business continuity processes as well as other matters relating to the Cybersecurity Incident, including business prospects and opportunities. The forward-looking information reflects management's current beliefs and is based on information currently available to NSPI'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. All such forward-looking information in this AIF is provided pursuant to safe harbour provisions contained in applicable securities laws.

The forward-looking information in this AIF, including the documents incorporated herein by reference, may include, but is not limited to, statements regarding: NSPI's revenue and earnings and cash flow; the growth and diversification of NSPI's business and rate base; NSPI's expected compliance with the regulation of its operations; the provision of electricity through the Maritime Link; NSPI's environmental initiatives and expected compliance with federal and provincial standards; the expected timing of regulatory decisions; forecast capital investments; the nature, timing and costs associated with certain capital projects; the expected impact on NSPI of challenges in the global economy; estimated energy consumption rates; the expectation that NSPI will continue to have reasonable access to capital in the near to medium terms; expected debt maturities, repayments and renewals; expectations about increases in interest expense and/or fees associated with debt securities and credit facilities; no material adverse credit rating actions expected in the near term; the successful development of relationships with various stakeholders, the impact of currency fluctuations; and expected changes in electricity rates.

The forecasts and projections that make up the forward-looking information are based on reasonable assumptions which include but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather or global climate change, other acts of nature or other major events; seasonal weather patterns remaining stable; no significant cyber or physical attacks or disruptions to NSPI's systems; the continued ability to maintain transmission and distribution systems to ensure their continued performance; continued investment in renewable

generation; no severe and/or prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and commodity prices; no significant variability in interest rates; expectations regarding the nature, timing and costs of capital investments of NSPI; expectations regarding rate base growth; the continued competitiveness of electricity pricing when compared with other alternative sources of energy; the continued availability of commodity supply; the absence of significant changes in government energy plans and environmental laws and regulations that may materially affect NSPI's operations and cash flows; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; no material decrease in market energy sales prices; favourable labour relations; and sufficient human resources to deliver service and execute NSPI's capital investment plan.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations include, but are not limited to: regulatory and political risk; change in law risk; system operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; changes in credit ratings; timing and costs associated with certain capital investments; expected impacts on NSPI 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 reduce demand for electricity; climate risk; weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; country risks; supply chain risk; environmental risks; foreign exchange; 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 the failure of information technology infrastructure and cybersecurity incidents, including 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 forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this AIF and in the documents incorporated herein by reference is qualified in its entirety by the above cautionary statements and, except as required by law, NSPI undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

CORPORATE STRUCTURE

Name and Incorporation

NSPI was incorporated on July 13, 1984 pursuant to the *Companies Act* (Nova Scotia). NSPI's principal, head and registered office is located at 1223 Lower Water Street, Halifax, Nova Scotia, B3J 3S8.

NSPI and its predecessor companies have been producing and supplying electricity in the Province for over 100 years.

NSPI holds a 100 per cent investment in NSPEMI, an energy business that purchases and sells electricity and natural gas in the United States energy commodity market. NSPEMI was incorporated on February 6, 2018, pursuant to the *Companies Act* (Nova Scotia) and commenced operations in 2019.

NSPI holds a 50 per cent indirect voting interest in WTI, a regulated utility, responsible for the Wasoqonatl transmission line project, creating a reliability intertie between Nova Scotia and New Brunswick.

NSPI is a wholly-owned operating subsidiary of Emera. Emera owns and operates mainly cost-of-service

rate-regulated electric and gas utilities in Canada, the United States and the Caribbean.

DESCRIPTION OF THE BUSINESS

General

NSPI is a vertically integrated regulated electric utility. It is the primary electricity supplier in the Province. NSPI has \$8.1 billion of assets and provides electricity generation, transmission and distribution services to approximately 565,000 customers.

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

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

NSPI serves the Province, which is the most populous of the four Atlantic Provinces of Canada and covers 55,284 square km of land and freshwater. As reported by Statistics Canada for 2025, the Province's population was estimated at 1,093,245 or 2.6 per cent of Canada's population.

Market and Sales

Electric sales volumes are primarily driven by weather, number of customers, customer usage, general economic conditions and DSM activities. Residential and commercial electricity sales are seasonal, with the first quarter historically generating the highest sales, reflecting colder weather and fewer daylight hours in the winter season. For more information describing the revenue generated for the year ended December 31, 2025, refer to the "Electric Revenues" section of the MD&A, which is incorporated herein by reference, a copy of which is available electronically under NSPI's profile on SEDAR+ at www.sedarplus.ca.

Revenue and Electricity Sales Volumes by Customer Class				
For the years ended December 31	Electric Revenues (%)		GWh Electric Sales Volumes (%)	
	2025	2024	2025	2024
Residential	56.2%	55.0%	49.4%	48.2%
Commercial	27.4%	27.5%	28.8%	28.8%
Industrial	14.2%	15.2%	19.6%	21.0%
Other	2.2%	2.3%	2.2%	2.0%
Total	100.0%	100.0%	100.0%	100.0%

Fuel for Generation and Purchased Power

To ensure reliability of service, NSPI aims to maintain a generating capacity greater than firm peak demand. The Company 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 coked ("petcoke") and 2 per cent is biomass-fueled generation. In 2025, NSPI began operations of two 50 MW 4-hour grid-scale battery facilities to further enhance reliability. In addition, NSPI has contracts to purchase renewable energy from IPPs, including COMFIT participants, which owns 573 MW of capacity. This includes IPPs in which NSPI has an ownership interest. NSPI has 153 MW of Maritime Link capacity, representing NLH's NS Block delivery obligations.

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 OBPS, availability of renewable generation, availability of energy from the NS Block, plant performance, and compliance with environmental regulations.

Fuel for generation and purchased power costs fluctuates year to year. For information describing the total production volumes by fuel source and for information related to the cost of electricity generation, refer to the "Fuel for Generation and Purchased Power" section of the MD&A, which is incorporated herein by reference, a copy of which is available electronically under NSPI's profile on SEDAR+ at www.sedarplus.ca.

System Operations and Generation

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

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

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

For further details on the IESO Nova Scotia and Nova Scotia Energy Reform Act, refer to the "Description of the Business — Environmental Matters" section below.

NSPI owns the following generating facilities:

- Four dual fired facilities:
 - Tufts Cove
 - 3 units dual fired with either heavy fuel oil or natural gas with a combined net output of 318 MW
 - 3 units in combined cycle fired on natural gas with a combined net output of 144 MW
 - Lingan
 - 4 units dual fired with either heavy fuel oil or solid-fuel with a combined net output of 607 MW.
 - Trenton
 - 2 units dual fired with either heavy fuel oil or solid-fuel with a combined net output of 304 MW.
 - Point Tupper
 - 1 unit dual fired with either heavy fuel oil or solid-fuel with a net output of 150 MW
- One solid-fuel generating station:
 - Point Aconi
 - 1 unit with a net output of 168 MW
- Three gas turbine facilities:
 - Burnside
 - 4 units with a combined net output of 132 MW
 - Tusket
 - 1 unit with a net output of 33 MW
 - Victoria Junction
 - 2 units with a combined net output of 66 MW
- 30 hydro generating stations located on 14 river systems throughout the Province, including Wreck Cove, the Halifax area, the Annapolis Valley and western Nova Scotia with a combined maximum output of 374 MW
- Digby Neck Wind Project (20 wind turbines) with a combined maximum output of 30 MW
- Nuttby Mountain Wind Project (22 wind turbines) with a combined maximum output of 51 MW
- Port Hawkesbury biomass co-generating facility with a net output of 43 MW
- Amherst Solar Farm with a net output of 2 MW
- A 47.4 per cent interest in Point Tupper Wind Project with a maximum output of 23 MW
- A 49 per cent interest in Sable Wind Project with a maximum output of 14 MW
- A 49 per cent interest in South Canoe Wind Project with a maximum output of 102 MW
- Two 50 MW 4-hour grid-scale battery facilities at Spider Lake and Bridgewater sites

NSPI also contracts with IPPs for renewable electricity as prescribed under the Nova Scotia Renewable Electricity Regulations, including energy from COMFIT. Most of these are wind generation projects placing NSPI amongst the leaders in wind integration in North America as a percentage of total generation capacity.

NLH's NS Block delivery obligations from Muskrat Falls commenced August 15, 2021. NLH is obligated to provide NSPI with approximately 900 GWh of energy annually for 35 years. For the first five years of the NS Block, NSPI is also entitled to receive approximately 240 GWh of additional energy from the Supplemental Energy block transmitted through the Maritime Link, with the final contracted delivery of supplemental block ending in Q1 2026. 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 TWh of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

Transmission and Distribution

NSPI transmits and distributes electricity from its generating stations to its customers. NSPI's transmission system consists of approximately 5,000 km of transmission facilities, including major substations at Lingan, Woodbine, Port Hastings, Hopewell, Onslow, Brushy Hill and Bridgewater connected to the transmission and distribution system. The distribution system consists of approximately 29,000 km of distribution facilities which includes distribution supply substations.

Regulatory Matters

Electricity Rates & Return on Equity

NSPI is regulated under a cost of service model, with rates set to recover prudently incurred costs of providing electricity service to customers, including a reasonable return to investors. NSPI's approved regulated ROE range for 2023, 2024 and 2025 was 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent. NSPI's approved ROE range remains unchanged for 2026, subject to approval by the NSEB in the 2025 GRA, for further details, refer to the "General Development of the Business — Regulatory Matters" section below.

Capital Investment

NSPI's 2025 Capital Plan was approved by the NSEB on August 19, 2025. NSP submitted a Capital Plan for 2026 to the NSEB for approval on December 12, 2025.

Capital investment for 2025, including AFUDC, was \$712 million (2024 — \$487 million and 2023 — \$451 million).

NSPI's rate base primarily includes net utility plant in service, construction work-in-progress, regulated assets and liabilities and working capital. The net utility plant in service consists of the utility plant at its original cost less accumulated depreciation. The components of rate base are subject to approval by the NSEB.

The NSEB prescribes depreciation rates and regulated accounting policies. Depreciation rates are reviewed periodically. The last depreciation study approved was completed in 2010. In 2025, a depreciation study was completed and remains subject to approval.

Employee Relations

NSPI had 2,486 employees as at December 31, 2025. 42 per cent of the full-time and term employees within the NSPI labour force are represented by a union and are subject to a collective labour agreement which expires March 31, 2026. There have been no labour disruptions since 1975.

Environmental Matters

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

NSPI currently estimates its environmental capital spending, excluding AFUDC, based upon present environmental laws and regulations will be approximately \$81 million during fiscal 2026 and is estimated to be \$111 million from 2027 through 2030. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and other pollutant emissions.

Nova Scotia OBPS

NSPI is a mandatory participant in Nova Scotia's OBPS carbon pricing program, which was effective January 1, 2023. Nova Scotia's OBPS implements GHG emissions performance standards for large industrial GHG emitters that vary by fuel type. GHG emissions in excess of the prescribed intensity standards are subject to a carbon price that starts at \$65 per tonne in 2023 and increase by \$15 per tonne annually, reaching \$170 per tonne by 2030. NSPI's regulatory framework provides for the recovery of costs prudently incurred to comply with carbon pricing programs pursuant to NSPI's FAM.

Renewable Electricity Regulations

Under the provincially legislated RER, starting in 2020, 40 per cent of electric sales must be generated from renewable sources. NSPI met this target in 2023 and 2024, and in 2025 met this target with more than 40 per cent of NSPI's electric sales coming from renewable sources, subject to a compliance filing.

On April 6, 2023, the Province levied a \$10 million penalty on NSPI for non-compliance with the RER compliance period ending in 2022. 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.

Nova Scotia Cap-and-Trade Program

NSPI was a participant in the Nova Scotia Cap-and-Trade Program and was subject to the 2019 through 2022 compliance period. NSPI received granted emissions allowances and was permitted to purchase up to five per cent of the credits available at provincial auctions. Any remaining allowance shortfall required the purchase of reserve credits directly from the Province. Lower than forecast Muskrat Falls energy received during the compliance period resulted in the increased deployment of higher carbon-emitting generation sources. On March 16, 2023, the Province provided NSPI with additional emissions allowances sufficient to achieve compliance with the 2019 through 2022 compliance period. Compliance costs accrued of \$166 million related to the anticipated purchase of emissions credits were reversed in Q1 2023. Credits NSPI purchased from provincial auctions in the amount of \$6 million were not refunded and no further costs were incurred to achieve compliance with the Nova Scotia Cap-and-Trade Program.

Nova Scotia Energy Reform Act

On April 5, 2024, the Province enacted Bill 404 - Energy Reform (2024) Act. This legislation implements certain recommendations made by the Clean Electricity Solutions Task Force, which was established by the Province to advise the provincial government on Nova Scotia's transition away from coal to more renewable sources of energy. The legislation enacted the Energy and Regulatory Board Act, which established the NSEB. The NSEB will regulate energy and utility entities in Nova Scotia, with a mandate of increased focus on meeting energy transition demands. The legislation also enacts the More Access to Energy Act, which provides for the establishment and phased transition to the IESO Nova Scotia.

On October 15, 2025, 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.

Compliance and Permits

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

Conformance with legislative and Company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed for the three years ended December 31, 2023 through December 31, 2025.

There have been several recent environmental developments from both the Government and the Province, as described in the "Environmental Matters" under the "General Development of the Business" section, below. NSPI is engaging with the Government, the Province, customers and stakeholders to work towards achieving these requirements, goals and targets with a focus on customer affordability. 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.

Risk Factors

Refer to the "Enterprise Risk and Risk Management" section of NSPI's MD&A and the "Principal Financial Risks and Uncertainties" section of note 21, Commitments and Contingencies, to the consolidated financial statements at December 31, 2025, which is incorporated herein by reference, a copy of which is available electronically under NSPI's profile on SEDAR+ at www.sedarplus.ca.

GENERAL DEVELOPMENT OF THE BUSINESS

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

Regulatory Matters

FAM

NSPI has a NSEB approved FAM, allowing NSPI to recover fluctuating Fuel Costs from customers through annual fuel rate adjustments. Differences between prudently incurred Fuel Costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

On April 17, 2024, the NSEB approved the sale of \$117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the \$117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. NSPI is collecting the amortization and financing costs related to the \$117 million from customers on behalf of Invest Nova Scotia over a 10-year period which began in Q2 2024 and is remitting those amounts to Invest Nova Scotia quarterly.

On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSPML and the Province of Nova Scotia on terms and conditions for a federal loan guarantee of \$500 million in debt to be issued by NSPML to help Nova Scotia customers manage unrecovered costs of the replacement energy

that was required during the several years of delay in the Muskrat Falls hydroelectricity project. On November 29, 2024, the NSEB approved NSPML's application to issue the debt, transfer the proceeds to NSPI as a refund of a portion of previous NSPML assessment payments, and to increase its annual assessment charge to NSPI to recover the refund and related financing costs over a 28-year period. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance. On February 18, 2025, the NSEB approved NSPI's application to increase 2025 fuel rates to service the incremental NSPML debt.

2022 GRA and Settlement Agreement

On February 2, 2023, the NSEB approved the GRA Settlement Agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and further average increases of 6.5 per cent on January 1, 2024, with any under or over-recovery of Fuel Costs addressed through the NSEB's established FAM process. On March 27, 2023, the NSEB issued a final order approving the electricity rates effective on February 2, 2023.

The Settlement Agreement established a storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the NSEB for recovery of costs if major storm restoration expense exceeds approximately \$10 million in a given year. The storm rider was effective as of February 2, 2023, the GRA decision date. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application. On December 2, 2024, the NSEB approved the recovery of \$24 million of major storm restoration and incremental financing costs deferred to NSPI's storm rider in 2023 to be recovered over a 12-month period beginning on January 1, 2025 and concluding by December 31, 2025.

The Settlement Agreement also established a DSM rider, allowing NSPI to recover costs associated with DSM programs developed and delivered by EfficiencyOne, a third-party regulated utility. The DSM rider was effective as of February 2, 2023, the GRA decision date. Differences between DSM program costs and amounts recovered from customers through electricity rates are deferred to a DSM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

2025 GRA

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.

Maritime Link

NSPI has a contractual obligation to pay NSPML, a related party, for the use of the Maritime Link over approximately 38 years from its January 15, 2018, in-service date.

On September 25, 2024, NSPI and NSPML filed applications with the NSEB related to the federal loan guarantee. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance as a refund of a portion of previous NSPML assessment payments. For further details, refer to the "FAM" section above.

NSPML received NSEB approval to collect up to \$201 million from NSPI for the recovery of costs associated with the Maritime Link in 2025 (2024 — \$164 million, 2023 — \$164 million), subject to a monthly holdback of up to \$2 million which began in April 2022 and increased to \$4 million per month beginning December 2023. The 2025 approved costs include \$158 million related to the 2025 annual cost

assessment and a supplemental assessment of \$43 million as part of the repayment of the federal loan guarantee.

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.

Hurricane Fiona

On June 27, 2024, the NSEB approved the deferred recognition of \$25 million in incremental operating costs incurred during the Hurricane Fiona storm restoration efforts in September 2022. Following the NSEB approval, the \$25 million was reclassified to “Regulatory assets” from “Other long-term assets”. The NSEB also directed NSPI to reclassify \$10 million of undepreciated costs related to assets retired because of Hurricane Fiona to “Regulatory assets” from “Property, plant and equipment” on the Condensed Consolidated Balance Sheets. NSPI began amortizing both of these regulatory assets over a 10-year period beginning on July 1, 2024.

BESS Project

On June 13, 2024, the NSEB approved \$238 million of capital investment, including AFUDC, for the BESS Project. The project is comprised of three 50 MW, four-hour battery facilities. As of December 31, 2025, two facilities are in service and the third facility is expected to be in service in 2026.

FAM Audit

Pursuant to the FAM Plan of Administration, NSPI’s fuel costs are subject to independent audit. On February 21, 2024, the NSEB’s decision on the FAM audit findings and recommendations relating to fiscal 2020 and 2021 were publicly released and included one disallowance. The disallowance of \$3 million was recorded in Q1 2024 in “FAM and other deferrals” with the associated interest expense of \$1 million recorded in “Interest expense, net”. The total \$4 million was returned to customers through the FAM.

On October 16, 2025, the NSEB’s decision on the FAM audit findings and recommendations relating to fiscal 2022 and 2023 were publicly released and included a disallowance of \$1 million plus associated interest. The impact of the disallowance was recorded in Q4 2025 in “FAM and other deferrals”.

For more information on NSPIs regulatory matters, refer to note 5, Regulatory Matters, in the consolidated financial statements as at December 31, 2025, which is incorporated herein by reference, a copy of which is available electronically under NSPI’s profile on SEDAR+ at www.sedarplus.ca.

Energy Efficiency Legislation

In April 2014, the Province announced energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of customers in the Province effective January 1, 2015. The legislation also required NSPI to purchase electricity efficiency and conservation activities from EfficiencyOne when it is cheaper than generation on a go-forward basis. The NSEB approved the implementation of the 2015 DSM deferral set at \$35 million which was recoverable from customers over an eight-year period beginning in 2016. A portion of the deferral was financed and advanced to NSPI by EfficiencyOne. As of December 31, 2023, the DSM deferral has been fully recovered from customers and the balance due to EfficiencyOne has been repaid.

In September 2022, the NSEB approved a budget of \$173 million for the three-year period of 2023 through 2025, which was reduced by \$4 million in 2023 as a result of the accumulated underspend by EfficiencyOne in the 2020 through 2022 period. DSM program costs for 2021, 2022 and 2023 were not

deferred.

Electricity Reform Act

The Electricity Reform Act was approved by the Province in December 2013. The legislation permits licensed retail suppliers to sell renewable, low impact electricity generated within the Province directly to retail customers in the Province. The legislation requires NSPI, in consultation with stakeholders, to develop related tariffs for approval by the NSEB. The tariffs, which enable “renewable to retail” transactions, were approved by the NSEB in March 2016. As at December 31, 2025, one license has been issued by the NSEB to a retail supplier. Sales from a licensed retail supplier to retail customers are permitted effective October 18, 2022. The licensed retail supplier has indicated its intention to commence sales in 2026.

Environmental Matters

NSPI is subject to regulation by federal, provincial, and municipal authorities regarding environmental matters related to its utility operations. This includes laws setting GHG emissions standards, renewable energy targets and air emissions standards. NSPI is also subject to laws regarding waste management, wastewater discharges and aquatic and terrestrial habitats. 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 refer to the “Enterprise Risk and Risk Management” section of the MD&A, incorporated herein by reference, a copy of which is available electronically under NSPI’s profile on SEDAR+ at www.sedarplus.ca. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

Clean Energy Transition

As part of its IRP process, NSPI filed an updated IRP Action Plan and Roadmap with the NSEB in August of 2023. On October 11, 2023, the Province released the 2030 Clean Power Plan which outlines the Province’s strategy to move off coal and reach 80 per cent renewable electricity sales by 2030. There is strong alignment between the Province’s 2030 Clean Power Plan and the Evergreen IRP Action Plan, demonstrating collaboration between NSPI and the Province.

The Province’s 2030 Clean Power Plan is centered around the addition of over 1,000 MW of onshore wind capacity and up to 300 MW of solar capacity, which is either currently in development by IPPs or planned for future procurement by the Province. As acknowledged in the Plan, capital investment in Nova Scotia’s grid will be required to integrate this additional renewable energy into the system, while continuing to provide safe, reliable electricity to customers. This includes investment in energy storage technologies to store intermittent renewable energy, upgraded inter-provincial transmission infrastructure to provide reliability and grid modernization investments to support the increased proportion of intermittent renewable energy on the system. In the medium term, investment in Nova Scotia’s thermal fleet will be required to continue to provide reliable firm capacity, including the conversion of select coal units to lower-emitting energy sources and the development of new fast-acting generating capacity resources to address growing demand and maintain reliability during periods of peak demand and low renewable generation. On December 12, 2025, NSPI filed *The Updated Path* to 2030 with the NSEB as part of the 2026 Capital Plan, which provides a detailed and specific plan outlining how NSPI will achieve the 2030 obligations, which is fully aligned with the Province’s 2030 Clean Power Plan. The Updated Path supersedes the *The Path to 2030* NSPI filed with the NSEB on December 22, 2023.

NSPI is working with both the federal and provincial governments to determine the appropriate funding in Nova Scotia to facilitate these projects while minimizing costs for customers. Capital investment by NSPI will be dependent on the sources of funding and ownership structures in place to facilitate these investments. Therefore, the total impact to NSPI and incremental cost to customers of the clean energy transition is not known at this time.

Renewable Electricity Regulations

The Province has established targets with respect to the percentage of renewable energy in NSPI's generation mix. Under the RER, the Company currently has a provincially mandated target of achieving at least 40 per cent of energy sales generated from renewable sources each year from 2020 through 2029. Beginning in 2030, the RER mandates that 80 per cent of electric sales be generated from renewable sources. Further, the Nova Scotia "Environmental Goals and Climate Change Reduction Act" established the goal to phase out coal-fired electricity generation by 2030.

NSPI continues to work with both the provincial and federal governments on measures to address generation mix targets. For further information on the current RER compliance period refer to the "Description of the Business — Environmental Matters" section above.

Greenhouse Gas Emissions

NSPI is subject to GHG emission caps for the 2010 through 2030 period as outlined in the "Nova Scotia Greenhouse Gas Regulations" and further updated by Order in Council in 2013. The emission cap reduces from 10 megatonnes in 2010 to 4.5 megatonnes in 2030. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Pursuant to an Equivalency Agreement entered into between the Province and the Government of Canada in 2014 and renewed through 2029, these provincial regulations have been deemed equivalent to, and have exempted Nova Scotia from the application of federal GHG emissions regulations which would effectively require the retirement or conversion of coal-fired electricity generating units by the earlier of 50 years from commissioning or 2030. Over the decade, NSPI will work to comply with the decreasing emission caps through a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

Effective January 1, 2023, the Province enacted amendments to the Environment Act which provided the framework for Nova Scotia to implement an OBPS to comply with the Government's 2023 through 2030 carbon pollution pricing regulations. The Government approved the Province's proposed system, however the OBPS will be subject to an interim review by the Government of the standards effective for 2026. The final Output-Based Pricing System Reporting and Compliance Regulations were prescribed by Order in Council dated January 30, 2024. Nova Scotia's OBPS implements GHG emissions performance standards for large industrial GHG emitters that vary by fuel type. GHG emissions in excess of the prescribed intensity standards will be subject to a carbon price that starts at \$65 per tonne in 2023 and will increase by \$15 per tonne annually, reaching \$170 per tonne by 2030. NSPI is a mandatory registrant under the OBPS. For further information refer to the "Description of the Business — Environmental Matters" section above.

On December 17, 2024, ECCC released a finalized version of the Clean Electricity Regulations (CER). The CER establish performance standards to significantly limit GHG emissions from fossil fuel-generated electricity starting in 2035 and help facilitate the Government of Canada's intention of achieving a net-zero electricity grid by the same year. Compliance with the finalized version of the CER is not anticipated to require significant capital investment incremental to NSPI's planned capital investment driven by the Province's goals to transition off coal and reach 80 per cent renewable electricity sales by 2030.

NSPI continues to work with both the provincial and federal governments on measures to address their carbon reduction goals.

Air Quality Regulations

NSPI is subject to emission cap requirements for mercury, SO₂ and NO_x as prescribed in the Nova Scotia Air Quality Regulations. The Air Quality Regulations limit net mercury emissions to 35 kg per year for the period of 2020 through 2029. Beginning in 2021, new emissions compliance periods for SO₂ and NO_x came into effect. Refer to the "Enterprise Risk and Risk Management – Air Quality Regulations" section of the Company's MD&A, incorporated herein by reference, for the detailed compliance periods

and emission caps.

NSPI is currently within, or forecasts the ability to meet, the prescribed limits for the current compliance periods. For the compliance periods ending in 2022, NSPI exceeded the prescribed limits for Mercury and SO₂. As per the Regulations, NSPI can compensate for the excess Mercury and SO₂ emissions within the three years following the year of exceedance, by reducing emissions equal to the amount of the excess emissions or can apply for an exemption by the Minister citing “unusual and unavoidable circumstances”. NSPI compensated for the excess mercury emissions within three years ending in 2025.

NSPI received a Certificate of Variance from Nova Scotia Environment and Climate Change on January 12, 2024, which allows NSPI to compensate the excess 2022 sulfur dioxide emissions by end of 2029 as opposed to by the end of 2025. NSPI received a Certificate of Variance from Nova Scotia Environment and Climate Change on March 25, 2025 which superseded the previous Certificate of Variance, and provides NSPI flexibility on the timing of SO₂ emissions in the 2025 through 2034 period, including compensating for the excess SO₂ emissions related to 2022. The longer timeframe will enable NSPI to recover the excess emissions with no incremental costs to customers while ensuring a reliable electricity grid.

Other Legislation

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

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

In April 2023, the Province enacted amendments to the Electricity Act which will allow the Province to issue requests for proposals for energy-storage in Nova Scotia, similar to the existing procurement process for renewable energy. In addition, the amendments to the Electricity Act allow the Governor in Council to approve unique or innovative energy storage projects that provide benefits to the electric system and reduce costs for customers.

Cybersecurity Incident

On April 25, 2025, NSPI discovered the Cybersecurity Incident involving unauthorized access into certain parts of its IT network and servers supporting portions of its business applications. There was no disruption to any of NSPI’s physical operations.

The Company implemented business continuity processes for certain impacted business and administrative functions. The systematic restoration of affected IT systems and corresponding transition away from business continuity process continues to progress in a planned, controlled and phased approach. The Company maintains cyber insurance coverage and is working with the insurer on the claims process. In Q4 2025, the Company recognized \$1 million, after-tax, in costs related to the Cybersecurity Incident. For the year ended December 31, 2025, the Company recognized \$7 million in after-tax costs related to the Cybersecurity Incident. For information on the risks associated with

cybersecurity incidents generally, refer to the 'Enterprise Risk and Risk Management' section of the MD&A, which is incorporated herein by reference, a copy of which is available electronically under NSPI's profile on SEDAR+ at www.sedarplus.ca.

Income Taxes

On June 20, 2024, Bill C-59, an Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023, and certain provisions of the budget tabled in Parliament on March 28, 2023, was enacted. Bill C-59 includes the EIFEL regime, which is effective January 1, 2024. EIFEL applies to limit a company's net interest and financing expense deduction to no more than 30 per cent of earnings before interest, income taxes, depreciation, and amortization for tax purposes. Any denied interest and financing expenses under the EIFEL regime can be carried forward indefinitely. There are no impacts required to be recognized in the Company's financial statements for the years ended December 31, 2024 and December 31, 2025.

Financing Activity

Credit Facilities

In July 2022, NSPI entered into a \$400 million non-revolving term facility set to mature July 15, 2024. The credit agreement contains customary representation and warranties, events of default and financial and other covenants and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from this issuance were used for general corporate purposes. In June 2024, NSPI amended and restated its non-revolving term facility, primarily to extend the maturity from July 2024 to June 2025 and decrease the amount of the facility from \$400 million to \$300 million. There were no other material changes in commercial terms from the prior agreement. On December 16, 2024, NSPI repaid its \$300 million unsecured non-revolving credit facility set to mature in June 2025.

In June 2024, NSPI amended and restated its revolving credit facility, primarily to extend the maturity from December 2027 to June 2029. There were no other material changes in commercial terms from the prior agreement.

On June 13, 2024, NSPI entered a non-revolving credit facility to finance the BESS Project. NSPI can request funds under the facility quarterly for amounts related to incurred BESS Project costs up to the total commitment of the lesser of \$120 million and 45.06 per cent of the total eligible BESS Project costs over the term of the agreement. The facility will be available until 6 months after completion of the BESS Project, not to exceed May 21, 2027 and matures 20 years following the availability period.

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.

Note Issuances

On March 24, 2023, NSPI completed a \$300 million unsecured note issuance that bears interest at a rate of 4.95 per cent and has a maturity date of November 15, 2032. On the same date, NSPI completed a \$200 million unsecured note issuance that bears interest at a rate of 5.36 per cent and has a maturity date of March 24, 2053. Proceeds from these issuances were added to the general funds of the Company and applied primarily to refinance existing indebtedness, including bank indebtedness, to finance capital expenditures and for other general corporate purposes.

Changes in Business Expected During 2026

Operations

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

USGAAP – Exemptive Relief and Companies Act Relief

NSPI was granted Exemptive Relief on September 13, 2022 and Companies Act Relief on October 12, 2022, each allowing NSPI to continue to report its financial results in accordance with USGAAP. The Exemptive Relief and Companies Act Relief will terminate on the earliest of: (i) January 1, 2027; (ii) if the Company ceases to have rate-regulated activities, the first day of the Company's financial year that commences after the Company ceases to have rate-regulated activities; and (iii) the first day of the Company's financial year that commences on or following the later of: (a) the effective date prescribed by the IASB for the Mandatory Rate-regulated Standard; and (b) two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard. The Exemptive Relief and Companies Act Relief replaces similar relief that had been granted to NSPI in 2018 and would have expired by no later than January 1, 2024.

On January 28, 2021, the IASB published an Exposure Draft Regulatory Assets and Regulatory Liabilities, which proposes the accounting model under which a company subject to rate regulation that meets the scope criteria would recognize regulatory assets and liabilities. The proposed effective date is annual reporting periods beginning on or after a date 18-24 months from the date of publication of the standard. The company will continue to monitor the development of the standard and assess the impact on the existing Exemptive Relief and Companies Act Relief.

CAPITAL STRUCTURE

The authorized capital of NSPI consists of an unlimited number of common shares, all without nominal or par value, and an unlimited number of first preferred shares and second preferred shares. All of the outstanding common shares are fully paid and non-assessable. There are no preferred shares outstanding.

Common Shares

As at December 31, 2025, NSPI had 173,517,299 common shares outstanding, all of which are owned by Emera. The common shares carry one vote per share and, subject to the prior rights of holders of any preferred shares, each common share entitles the holder to share rateably in any dividends or other distributions to the shareholders. The foregoing is subject to the "Share Ownership Restrictions" section below.

Redeemable Preferred Shares

As at December 31, 2025, NSPI had 400,000 redeemable preferred shares outstanding. For more information, refer to note 21, Redeemable Preferred Shares, in the consolidated financial statements as at December 31, 2025, which is incorporated herein by reference, a copy of which is available electronically under NSPI's profile on SEDAR+ at www.sedarplus.ca

Share Ownership Restrictions

Pursuant to the *Nova Scotia Power Privatization Act* (Nova Scotia), the articles of association of NSPI provide that no person, together with associates thereof, may subscribe for, have transferred to that person, hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, in

the aggregate, voting shares of NSPI to which are attached more than 15 per cent of the votes that may ordinarily be cast to elect directors, other than votes that may be so cast by or on behalf of Emera. Non-residents of Canada may not subscribe for, have transferred to them, hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, or vote, in the aggregate, voting shares of NSPI to which are attached more than 25 per cent of the votes that may ordinarily be cast to elect directors. Votes cast by non-residents on any resolution at a meeting of common shareholders of NSPI will be pro-rated so that such votes will not constitute more than 25 per cent of the total number of votes cast.

The common shares are considered to be voting shares for the purposes of the constraints of ownership. Emera is not subject to the constraint on individual ownership by virtue of the *Nova Scotia Power Reorganization (1998) Act*.

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

CREDIT RATINGS

NSPI has been assigned the following credit ratings by the Rating Agencies¹:

	DBRS	S&P
Issuer	BBB (high) (Stable)	BBB- (Stable)
Senior unsecured debt	BBB (high) (Stable)	BBB- (Stable)
Commercial paper	R-2 (high) (Stable)	A-3 (Cdn) (Stable)

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

In February 2023, S&P affirmed its BBB- issuer rating and negative outlook for NSPI. In March 2024, S&P affirmed its BBB- issuer rating and negative outlook for NSPI. In January 2025, S&P affirmed its BBB- issuer rating and revised its outlook to stable from negative.

In December 2023, DBRS affirmed its BBB (high) rating and stable trend for NSPI. In December 2024, DBRS affirmed its BBB (high) rating and stable trend for NSPI. In December 2025, DBRS affirmed its BBB (high) rating and stable trend for NSPI.

DBRS

DBRS' long term debt rating scale ranges from AAA to D, representing the range from highest to lowest quality of such rated securities. The "BBB" rating is the fourth highest rating category out of a total of ten categories employed by DBRS. Debt instruments that are rated in the BBB category by DBRS are considered by DBRS to be of adequate credit quality. DBRS also notes that the capacity for payment of financial obligations is considered acceptable and may be vulnerable to future events. The assignment of a "(high)" or "(low)" designation after a rating indicates the relative standing within a particular category.

The rating of R-2 (high) from DBRS with respect to NSPI's commercial paper is the fourth highest of ten available rating categories. DBRS considers commercial paper rated R-2 (high) to be of adequate credit quality. DBRS also notes that the capacity for the payment of commercial paper as it falls due is

acceptable and the obligation may be vulnerable to future events.

S&P

S&P's obligor's long term debt rating scale ranges from AAA to D, representing the range from highest to lowest quality of such rated securities. A rating of BBB by S&P is the fourth highest of ten major categories. According to the S&P rating system, an obligor with debt securities rated BBB has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to weakened capacity of the obligor to meet its financial commitments. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within a particular rating category.

The rating of A-3 (Canadian scale) from S&P with respect to NSPI's commercial paper is the third highest of six available rating categories and indicates that the obligation is more susceptible to adverse effects and changes in circumstances and economic conditions than obligations in higher ranked categories. S&P also notes, however, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments.

Payments to Rating Agencies

NSPI has made, or will make, payments in the ordinary course to the Rating Agencies in connection with the assignment of ratings on both NSPI and its securities. As the Rating Agencies did not provide any other services to NSPI in the past three years, NSPI did not make any other payments to the Rating Agencies in 2023, 2024 and 2025.

DIVIDENDS

Any dividend payments are at the Directors' discretion based upon earnings and capital requirements and such other factors as the Directors may consider relevant.

During the year ended December 31, 2025, NSPI did not pay dividends on its common shares (2024 — nil and in 2023 — nil).

RETURN OF CAPITAL

NSPI returned \$340 million of capital (2024 — nil and in 2023 — nil) to Emera without a reduction in the amount of common shares outstanding.

MARKET FOR SECURITIES

Trading Price and Volume

NSPI's common shares are owned by Emera and are not publicly traded.

DIRECTORS AND OFFICERS

Directors

The following information is provided for each Director of NSPI as at December 31, 2025:

Name and Residence	Director Since ⁽¹⁾	Principal Occupations During Past Five Years
J. Lee Bragg Fall River, Nova Scotia, Canada	2010	Executive Chair of Eastlink, a cable and communication company, and its associated communications companies. Previously held various management positions with the Bragg Group of Companies.
Raymond E. Ivany ⁽²⁾ Wolfville, Nova Scotia, Canada	2011	Former President and Vice Chancellor of Acadia University from April 2009 to June 2017. Currently sits on the Board of Directors of the Bank of Canada. Previously, the Chair of the Worker's Compensation Board of Nova Scotia and President and Chief Executive Officer of the Nova Scotia Community College.
Sandra Greer Halifax, Nova Scotia, Canada	2014	Former President and Chief Executive Officer of Amirix Systems Inc (now Innovasea Canada) (2002 – 2012) a company engaged in the design, manufacture and worldwide export of acoustic marine tracking devices. Currently sits on the Board of Innovasea, based in the US, and the Board of Precision Biologic. Previously, Chair of the Board of the Nova Scotia Community College as well as former member of Acadia University Board of Governors, and the NSBI Board of Directors.
Scott C. Balfour Halifax, Nova Scotia, Canada	2016	A Director and President and Chief Executive Officer of Emera Inc. (Emera) since March 2018. A Director of many Emera subsidiaries. Former director of Martinrea International Inc. He was Chief Operating Officer of Emera from 2016 to 2018 and Executive Vice President and Chief Financial Officer of Emera from April 2012 to March 2016. From 1994 to 2011 he was Chief Financial Officer and then President of Aecon Group Inc., a Canadian publicly traded construction and infrastructure development company. Past Chair of the Ontario Energy Association.
J. Mark Rodger Toronto, Ontario, Canada	2018	Senior Counsel and Toronto Regional Co-Chair of the Energy Markets & Infrastructure Group with the law firm, Borden Ladner Gervais LLP, Toronto office. Chairman of the Board of City of Peterborough Holdings Inc. Former Chair of the Board of Logistec Corporation, Montreal Quebec.
Julia Rivard Dexter Fall River, Nova Scotia, Canada	2020	Co-Founder and Chief Executive Officer, Shoelace Learning Inc.. A former Olympian and previously served as Chief Executive Officer of SheepDogInc.ca. Former Vice Chair of the Board of Governors of the Nova Scotia College of Art and Design, a member of the Canadian Olympic Committee, and past member of the Nova Scotia Premier's Advisory Council.
Peter Gregg Halifax, Nova Scotia, Canada	2020	President and Chief Executive Officer of NSPI since October 2020. Prior to that the President and Chief Executive Officer of the Independent Electricity System Operator in Ontario. Previously, the President and Chief Executive Officer of Enersource from 2014 to 2016 and before that Chief Operating Officer at Hydro One Networks.

Name and Residence	Director Since ⁽¹⁾	Principal Occupations During Past Five Years
Cassandra Dorrington Halifax, Nova Scotia, Canada	2021	President and Chief Executive Officer of Canadian Aboriginal and Minority Supplier Council, a not-for-profit organization since 2010. Current Chair of Elevate International and CFIA Departmental Audit Committee (DAC), Treasurer for Federation of African Canadian Economics (FACE) and Vice-Chair for the Future of Hockey Lab, and Board member for PCO's DAC. Founding member of both Supplier Diversity Advisory Committee (SDAC) and Global Supplier Diversity Alliance (GSDA). Current member of the Supplier Advisory Council for PSPC. Former board executive member for Black Business Enterprises, CPA Canada and CMA Canada National Board, Tribe and Dalhousie University Board of Governors..
Vivek Sood Halifax, Nova Scotia, Canada	2024	Former Executive Vice President, Related Businesses, Sobeys Inc (2004 – 2024) with national responsibility for pharmacy, wholesale, fuel, convenience, and liquor business for the publicly traded Empire Company Limited. Member of Crombie REIT's Board of Trustees since 2024.
Daniel P. Muldoon ⁽³⁾ Halifax, Nova Scotia, Canada	2025	Former Executive Vice President, Project Development and Operations Support, Emera, Former Executive Vice President, Major Renewable and Alternative Energy, Emera; President and Chief Operating Officer of Compressed Natural Gas (CNG), Emera; and President and Chief Operating Officer of Emera Utility Services. A past member of the executive committee for Cigre Canada – International Council on Large Electric Systems. Previously served on both the Transmission and Distribution Councils for the Canadian Electricity Association and is a past Board Member of the Cape Breton Partnership.

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

(2) Appointed Lead Director in May 2024.

(3) Daniel P. Muldoon appointed to the Board on February 11, 2025. Mr. Muldoon retired from Emera Inc. effective June 30, 2025.

As at December 31, 2025, no Directors own common shares of NSPI.

Officers

The Officers of NSPI as at December 31, 2025 were as follows:

Name, Position and Residence	Principal Occupations During Past Five Years
Peter H. Gregg President and CEO Halifax, Nova Scotia, Canada	President and Chief Executive Officer of NSPI since October 2020 ⁽¹⁾ .
Jared Green, CPA, CA Chief Financial Officer Halifax, Nova Scotia, Canada	Chief Financial Officer since December 2025. Previously served as President and Chief Executive Officer of TriSummit Utilities (previously AltaGas Canada).
David A. Pickles Chief Operating Officer	Chief Operating Officer since September 2022. From February 2021 to August 2022 Vice President of Electric Delivery for Tampa Electric. February 2018 to January 2021 Vice President of Energy Supply for

Name, Position and Residence	Principal Occupations During Past Five Years
Halifax, Nova Scotia, Canada	Tampa Electric and from 2014 to 2018 Vice President of Operations for Emera Energy.
R. Michael Roberts Chief Human Resources Officer Halifax, Nova Scotia, Canada	Chief Human Resources Officer since December 2014. Previously, President, Optimum Talent Atlantic of Halifax. Prior to that, Vice President, Corporate Development at Irving Shipbuilding and Vice President, Human Resources at Bell Aliant.
Christopher H.C. Smith, CPA, CA Executive Vice President Finance, Legal and Regulatory Halifax, Nova Scotia, Canada	Executive Vice President Finance, Legal and Regulatory since December 2025. From March 2021 to December 2025 Executive Vice President Finance. From March 2017 to March 2021 Vice President Finance. Previously, at Heritage Gas Limited, from 2015 to 2017, President; from 2014 to 2015 Vice President, Business Development; and from 2004 to 2014, Vice President Finance and Business Services.
Mark Everett Corporate Secretary Halifax, Nova Scotia, Canada	Corporate Secretary since January 2024, and Director of Legal since January 2020. Previously Senior Solicitor for NSPI. Prior to that Legal Counsel for Justice Canada, from October 2008 to June 2012 and Solicitor from June 2006 to October 2008 at NSPI.

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

As at December 31, 2025, no Officers own common shares of NSPI.

CERTAIN PROCEEDINGS

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

1. are, as at the date of this AIF, or have been, within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company, including NSPI, that:
 - (a) was subject to an Order that was issued while the Director or Officer was acting in the capacity as director, chief executive officer or chief financial officer; or
 - (b) was subject to an Order that was issued after the Director or Officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;
2. are, as at the date of this AIF, or have been within ten years before the date of this AIF, a director or executive officer of any company, including NSPI, that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;
3. have, within the ten years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed nominee; or
4. have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or have entered in a settlement

agreement with a securities regulatory authority, or are subject to any penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

NO INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

MATERIAL CONTRACTS

NSPI has no material contracts other than those entered into in the ordinary course of its business.

EXPERTS

Ernst & Young LLP are the external auditors of NSPI. Ernst & Young LLP report that they are independent within the context of the CPA Code of Professional Conduct of the Chartered Professional Accountants of Nova Scotia.

ADDITIONAL INFORMATION

Additional information relating to NSPI may be found on SEDAR+ at www.sedarplus.ca or upon request to the Corporate Secretary, NSPI, P.O. Box 910, Halifax, N.S., B3J 2W5, telephone (902) 240-3547 or fax (902) 428-4008. Additional information, including Directors' and Officers' remuneration and indebtedness and principal holders of NSPI's securities is contained in NSPI's information circular. Additional financial information is provided in NSPI's consolidated financial statements and MD&A.

At any time, NSPI will provide to any person upon request to the Corporate Secretary, a copy of the Emera Code of Conduct.

APPENDIX A – DEFINITIONS

For convenience, terms used throughout this 2025 AIF of Nova Scotia Power Incorporated shall have the following meanings:

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

“**AIF**” means this 2025 Annual Information Form of NSPI;

“**BESS Project**” means Battery Energy Storage System Project;

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

“**Capital Plan**” means NSPI’s Annual Capital Expenditure Plan filed annually with the NSEB;

“**CEO**” means Chief Executive Officer;

“**CER**” means the Government’s Clean Electricity Regulations;

“**CIB**” means the Canada Infrastructure Bank;

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

“**Companies Act Relief**” means an order of the Nova Scotia Securities Commission pursuant to the *Companies Act* (Nova Scotia) exempting NSPI from the requirement to prepare its annual financial statements in accordance with IFRS;

“**Company**” means NSPI;

“**Cybersecurity Incident**” means the cybersecurity incident NSPI discovered on April 25, 2025, involving unauthorized access into certain parts of its Canadian IT network and servers supporting portions of its business applications;

“**DBRS**” means the credit rating agency Dominion Bond Rating Service Limited;

“**Directors**” means the directors of NSPI and “**Director**” means one of them;

“**DSM**” means demand side management;

“**Electricity Plan Act**” means the *Electricity Plan Implementation (2015) Act*;

“**Electricity Reform Act**” means the *Electricity Reform Act (Nova Scotia)*;

“**Emera**” means Emera Incorporated, a public company incorporated under the laws of the Province and traded on both the Toronto Stock Exchange and New York Stock Exchange under the symbol “EMA”, and the parent company of NSPI;

“**ECCC**” means Environment and Climate Change Canada;

“**EIFEL**” means excessive interest and financing expenses limitation;

“**Exemptive Relief**” means the relief granted to NSPI by Canadian securities regulators allowing NSPI to continue to report its financial results in accordance with USGAAP;

“**FAM**” means the fuel adjustment mechanism established by the NSEB;

“**Fuel Costs**” means prudently incurred fuel for generation and purchased power and certain fuel related costs;

“**FSP**” means Fuel Stability Plan;

“**GHG**” means greenhouse gas;

“GGPPA” means the *Greenhouse Gas Pollution Pricing Act*;

“Government” means the Government of Canada;

“GRA” means a General Rate Application filed with the NSEB;

“GWh” means the amount of electricity measured in gigawatt hours;

“IASB” means the International Accounting Standards Board;

“IFRS” means International Financial Reporting Standards;

“IPPs” mean independent power producers;

“IRP” means NSPI’s Evergreen Integrated Resource Plan;

“kg” means kilograms;

“km” means kilometres;

“LIL” means Labrador Island Link, a 1,100-km transmission line carrying energy from Muskrat Falls to Newfoundland;

“Mandatory Rate-regulated Standard” means IASB’s mandatory application of a standard within IFRS specific to entities with rate-regulated activities;

“Maritime Link” or **“Maritime Link Project”** means the transmission project including two 170-km sub-sea cables between the island of Newfoundland and the Province, developed by NSPML;

“MD&A” means NSPI’s Management’s Discussion and Analysis for the fiscal year ended December 31, 2025, a copy of which is available electronically under NSPI’s profile on SEDAR+ at www.sedarplus.ca;

“Muskrat Falls” means the Muskrat Falls hydroelectric project, a 824 MW hydroelectric generating facility at Muskrat Falls on the lower Churchill River;

“MW” means the amount of power measured in megawatts;

“MWh” means the amount of electricity measured in megawatt hours;

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

“NLH” means Newfoundland and Labrador Hydro, a company that is incorporated under a special act of the Legislature of the Province of Newfoundland and Labrador as a Crown corporation, and formerly Nalcor Energy;

“NERC” means North American Electric Reliability Corporation;

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

“Nox” means Nitrogen Oxide;

“NPCC” means Northeast Power Coordinating Council, Inc.;

“NS Block” means the electricity transmitted through the Maritime Link from Muskrat Falls;

“NSEB” means Nova Scotia Energy Board, formerly the UARB, an independent regulator of NSPI;

“IESO Nova Scotia ” means the Nova Scotia Independent Energy System Operator;

“NSPI” means Nova Scotia Power Incorporated, a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, Canada. NSPI is incorporated under the laws of the Province and is a wholly owned, direct or indirect subsidiary of Emera;

“NSPEMI” means NS Power Marketing Incorporated, a wholly-owned direct subsidiary of NSPI. NSPEMI is an

energy business that purchases and sells electricity and natural gas in the United States of America's energy commodity market and is incorporated under the laws of the Province;

"NSPML" means NSP Maritime Link Incorporated, a wholly owned direct subsidiary of Emera Newfoundland and Labrador Holdings incorporated under the laws of the Province of Newfoundland and Labrador that has developed the Maritime Link Project;

"OBPS" means output-based pricing system;

"Officers" means the executive officers of NSPI and **"Officer"** means one of them;

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

"Petcoke" means petroleum coke;

"PP&E" means Property, Plant, and Equipment;

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

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

"Rating Agencies" means collectively, DBRS and S&P, and "Rating Agency" means one of the Rating Agencies;

"RER" means the Nova Scotia Renewable Electricity Regulations.

"ROE" means return on equity;

"RSP" means rate stability plan;

"S&P" means the credit rating agency Standard & Poor's Rating Services;

"Sable Wind Project" means a 14 MW wind farm near Canso, Nova Scotia;

"SEDAR+" means the System for Electronic Documents Analysis and Retrieval;

"Settlement Agreement" means the comprehensive settlement agreement filed with the NSEB between NSPI and key customer representatives and participating interest groups in relation to NSPI's GRA filed in January 2022;

"SO2" means Sulphur Dioxide;

"South Canoe Wind Project" means a 102 MW wind farm near New Russell, Nova Scotia;

"TWh" means the amount of electricity measured in terawatt hours;

"UARB" means the Nova Scotia Utility and Review Board, see NSEB;

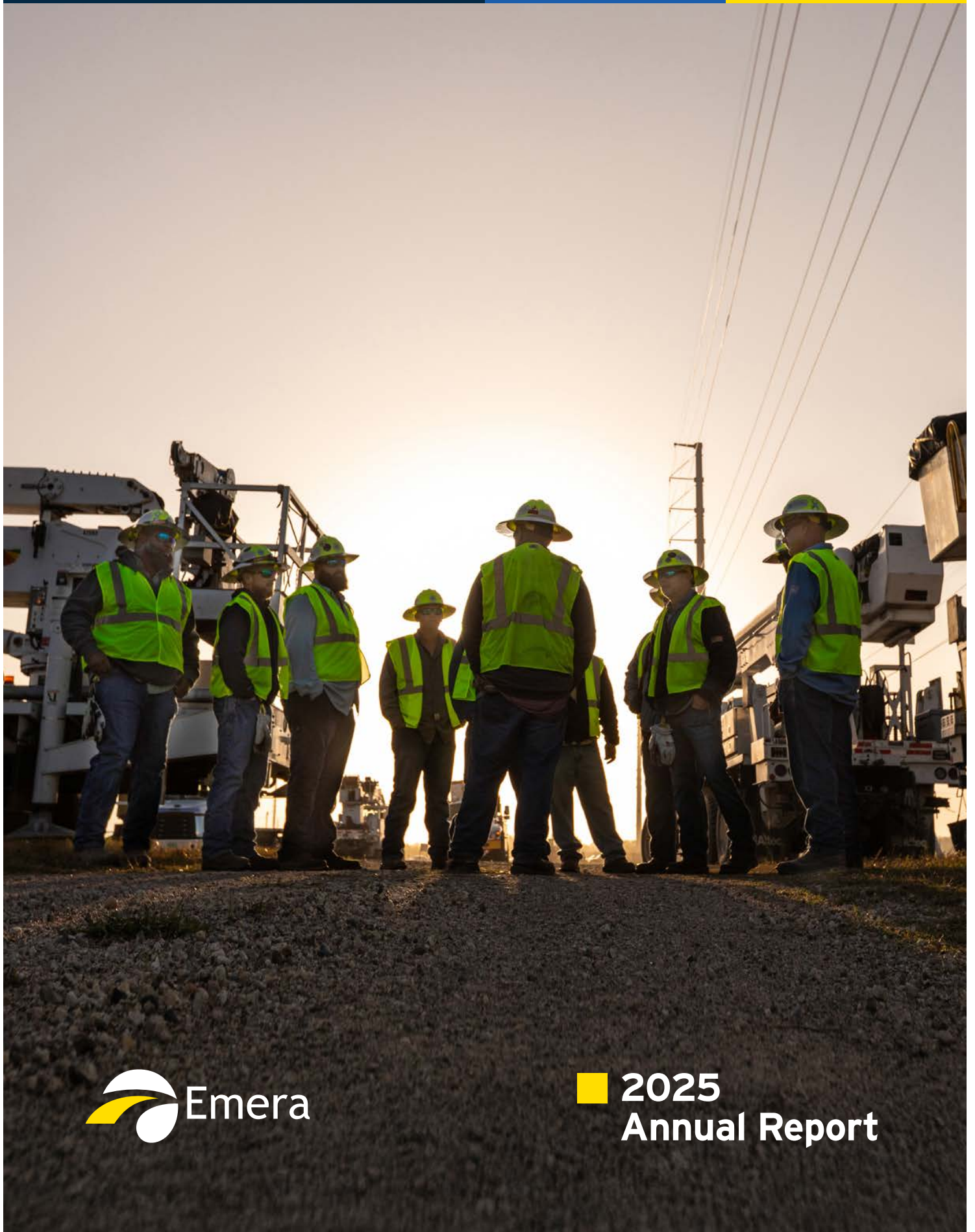
"USGAAP" means the accounting principles which are recognized as being generally accepted and which are in effect from time to time in the United States of America as codified by the Financial Accounting Standards Board, or any successor institute;

"WTI" means Wasoqonatl Transmission Incorporated, a regulated utility, wholly-owned by a newly formed limited partnership between NSPI, CIB and Wskijinu'k Mtmot'agnuow Agency

All amounts are in Canadian dollars except where otherwise stated.

Reference to "including", "include" or "includes" means "including (or includes) but is not limited to" and shall not be construed to limit any general statement preceding it to the specific or similar items or matters immediately following it.

The information presented in this 2025 AIF is as at December 31, 2025, unless otherwise specified.



■ 2025
Annual Report

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Emera at a Glance

Emera is a leading North American provider of energy services headquartered in Halifax, Nova Scotia. Emera delivers safe, clean, and reliable energy to customers through investments in regulated electric and natural gas utilities, and related businesses and assets.



\$45B
total assets



\$8.8B
revenue



6
electric and
natural gas utilities ⁽¹⁾



2.7M
customers



7,800
employees

Our Companies

As of March 1, 2026

Tampa Electric
Nova Scotia Power
Peoples Gas
New Mexico Gas ⁽²⁾
Emera Caribbean
Emera Newfoundland & Labrador
Emera Energy
Emera New Brunswick
Emera Technologies

Data on this page is as of December 31, 2025, unless otherwise indicated.

(1) Four electric utilities and two natural gas utilities.

(2) In August 2024, Emera entered into an agreement to sell New Mexico Gas. This transaction is expected to close in the first half of 2026.

Why Invest in Emera

Emera is at the forefront of a transformative era in energy with robust opportunities to invest on behalf of customers across the portfolio.

Our proven strategy and operational excellence enable us to capitalize on this growth.



Premium Portfolio of Regulated Utilities Focused in Florida

72%

of adjusted net income ⁽¹⁾, excluding Corporate costs, comes from our Florida operations

~80%

of capital plan through 2030 is focused in Florida in support of customer growth at Tampa Electric and Peoples Gas respectively

Constructive Regulatory Environments

95%

of adjusted net income ⁽¹⁾, excluding Corporate costs, derived from our regulated utilities

Visible Growth Plan

\$20B

capital investment plan through 2030 committed to renewable integration, grid reliability, and modernization

7%-8%

annualized, forecasted rate base growth through 2030 ⁽³⁾

Reliable Earnings and Dividend Growth

19 years

of consecutive dividend growth

1-2%

annual dividend growth target

5-7%

average adjusted EPS ⁽²⁾ growth target through 2030 ⁽³⁾

(1) Based on 2025 adjusted net income attributable to common shareholders ("adjusted net income"), excluding Corporate costs of \$380 million. Adjusted net income is a non-GAAP measure, which does not have a standardized meaning under United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2025 MD&A.

(2) Adjusted earnings per share ("EPS") is a non-GAAP ratio, which does not have standardized meaning under USGAAP. For more information, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2025 MD&A.

(3) Adjusted EPS and rate base growth forecasts use 2024 as base year.

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2025 Financial Highlights

\$3.49

Annual adjusted EPS ⁽¹⁾

72%

of adjusted net income ⁽¹⁾, excluding Corporate costs, comes from Florida ⁽²⁾

\$3.6B

capital invested in 2025, leading to an 8% annual increase in rate base

4.3%

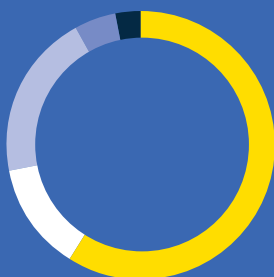
dividend yield ⁽³⁾

2025 Adjusted Net Income ⁽¹⁾

Excluding Corporate Costs ⁽²⁾

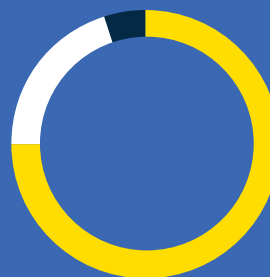
By Business Segment

- **59%** Florida electric
- **13%** Canadian electric
- **20%** Gas utilities and infrastructure
- **5%** Other
- **3%** Other electric



By Revenue Type

- **75%** Regulated electric
- **20%** Regulated gas
- **5%** Unregulated



Unless otherwise indicated, all data on this page is as of December 31, 2025, and currency is in Canadian dollars.

(1) Adjusted EPS and adjusted net income are a non-GAAP measure and non-GAAP ratio, respectively, which do not have standardized meaning under USGAAP. For more information, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2025 MD&A

(2) Based on 2025 adjusted net income, excluding Corporate costs of \$380 million.

(3) Based on Dec. 31, 2025 share price of \$67.64

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Who We Are

Our Strategy

We're focused on safely delivering reliable and cleaner energy at a pace that minimizes the cost impacts for customers at our utilities. Through our strategy, we're responding to the fundamental shift that's impacting the energy industry and delivering on the key trends that reflect the changing needs of utility customers: decarbonization, decentralization and digitalization.

Our Purpose

Energizing modern life and delivering a cleaner energy future for all.

Our Vision

To be the energy provider of choice for our customers, the employer of choice for our people, and a preferred choice for investors.

Our Values

- We put safety above all else.
- We put customers at the centre of everything we do.
- We value candour, respect and collaboration.
- We care for each other, the environment, and our communities.
- We set a high bar and take on big things.

Emera's Sustainable Energy Approach

Proven Record



20+ years of investments

- ✓ Wind in Nova Scotia
- ✓ Solar in Florida
- ✓ Big Bend modernization
- ✓ Maritime Link hydro

Real Progress



Reduced CO₂ emissions by nearly half ⁽¹⁾ while modernizing grids

- ✓ Replacing coal
- ✓ Integrating renewables
- ✓ Grid upgrades

Proactive & Adaptive



Responding to evolving drivers

- ✓ Severe weather risks & resilience
- ✓ Government policies & targets
- ✓ Electrification & demand
- ✓ Emerging technologies

Disciplined Investment



Sustaining momentum through customer-focused capital plan

- ✓ Grid reliability & modernization
- ✓ Renewable integration
- ✓ Technology adoption

Initiatives across our core operating jurisdictions ⁽²⁾ – paced with customer affordability in mind

- ✓ **Florida:** Strengthening reliability and affordability while modernizing the generation fleet via investments in solar, battery storage, fuel switching, long-term use of natural gas, and storm hardening.
- ✓ **Nova Scotia:** Strengthening reliability while aligning with provincial and federal climate policy ⁽³⁾ through investments in grid resilience, interties, hydro, battery storage, coal retirement, fuel switching, wind, and solar.

(1) Our reductions in CO₂ emissions are compared to 2005 levels and include CO₂ scope 1 generation emissions for TEC and NSPI only.

(2) Core jurisdictions refer to Emera's primary operating regions where regulated electric and gas utilities operate, including Nova Scotia (NSPI) and Florida (TEC & Peoples Gas Systems, Inc. ("PGS")).

(3) Activities in Nova Scotia are aligned with government climate targets of 80% renewable energy and coal-free electricity by 2030 and will be shaped by the decisions of the Nova Scotia Independent Energy System Operator ("IESO Nova Scotia") regarding future generation sources.

Letter from the Chair and the CEO

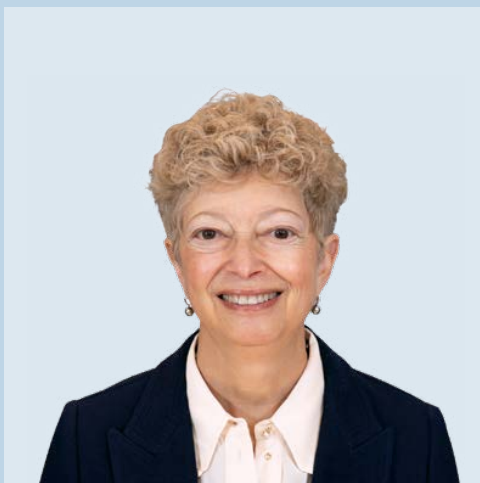
Fellow shareholders,

2025 was defined by meaningful progress for Emera, reflecting the benefit of years of disciplined investment, operational excellence, and continual focus on long-term strategy and delivery of value for our stakeholders. We also continued to strengthen our balance sheet and protect our investment grade credit metrics, prioritizing financial resilience alongside disciplined growth in a volatile environment. As a result, Emera's positioning is strong, with a stable and resilient business focused on enduring value creation.

We carry this momentum into 2026, while recognizing that discipline and focus have never been more important. Rising demand for energy, geopolitical volatility, government policy and regulatory requirements, rapid technological change, and greater expectations for reliable service at a manageable cost are placing higher demands on energy systems and the companies that operate them. Emera is meeting this moment—modernizing our electric and gas systems and strengthening overall system resilience—to deliver long-term value for customers amid broader economic pressures.

In Florida—the largest market Emera serves—population and economic growth are driving demand. In response, we advanced projects focused on system capacity, reliability, and storm resiliency. The addition of solar and storage resources, as well as system expansion investments to serve new electric and gas customers ensure we meet increased energy demand and population growth. In Nova Scotia, we are executing a five-year reliability plan that modernizes infrastructure, strengthens the grid, and supports the continued integration of renewables and other technologies. Each investment we make is sequenced to align with evolving energy requirements and manage customer costs.

Karen Sheriff
Chair, Board of Directors, Emera Inc.



Scott Balfour
President and Chief Executive Officer, Emera Inc.



2025 Highlights

Emera's momentum throughout 2025 came from consistent execution and commitment to operational excellence. Across our operations we advanced major capital projects, and in turn, hit key milestones.

We translated our capital plan into tangible outcomes—strengthening the systems our customers rely on every day and progressing strategic initiatives that position our business for the future. Some of the noteworthy items include:

- Tampa Electric opened its new headquarters and Bearss Operations Center (BOC) opened their doors in 2025. Engineered to withstand Category 5 hurricane conditions, the BOC is a state-of-the-art, 24/7 facility that enhances day-to-day reliability and enables rapid, safe storm response for Tampa Electric through even the most severe weather conditions.
- Two of three new 50-MW grid-scale battery sites went into operation in Nova Scotia, boosting system resilience and renewables integration. Developed through a partnership between Nova Scotia Power and all 13 Mi'kmaw communities in Nova Scotia, this project supports mandates to phase out coal from the generation mix and reach 80 per cent renewables by 2030. The third site is scheduled to come online in August 2026.
- Tampa Electric installed an additional 150 megawatts of solar generation, bringing their total to 1,505 megawatts. These solar investments continue to reduce exposure to volatile fuel costs and deliver real savings for customers.
- The Maritime Link remained a critical energy system in Atlantic Canada, delivering two-way underwater energy transmission between Nova Scotia and Newfoundland and Labrador. Continuing excellent operational performance in 2025, it provided 100 per cent monopole availability, delivering 2 TWh of clean hydroelectricity to Nova Scotia, and serving approximately 19 per cent of Nova Scotia Power's energy requirements for the year.

We also achieved several strategic milestones and made important progress that strengthened Emera's position this year. We took essential steps toward the sale of New Mexico Gas Company—filing a joint application with proposed purchaser Bernhard Capital Partners and proceeding through the November 14 hearing with the Public Regulation Commission. Closing is anticipated in the first half of 2026.



- In 2025, Tampa Electric opened its new headquarters and its 24/7 Bearss Operations Centre—strengthening reliability and accelerating storm response.

	Strategic Overview	Management's Discussion and Analysis	Consolidated Financial Statements	Emera Leadership and Board	Shareholder information	

In Florida, Peoples Gas achieved a constructive rate case outcome following collaborative engagement with stakeholders that supports continued investment and regulatory stability for customers. In Nova Scotia, Nova Scotia Power filed a consensus 2026-2027 General Rate Application (GRA), a uniquely customer-focused open-book approach of engaging with customer representatives before a regulatory filing to collectively discuss and agree upon the balance of the pace of critical reliability investments with rate impacts. Following a fulsome hearing process, a decision from the Nova Scotia Energy Board is pending.

Last but certainly not least, Emera began trading on the New York Stock Exchange on May 28, 2025, becoming the first Nova Scotia-headquartered company to list on NYSE. This listing broadens our access to U.S. capital and marks a milestone in Emera's journey.

Safety and Security

Safety remains our highest priority and the standard we hold ourselves to every day. In 2025, we continued to strengthen safety practices across our operating companies—assessing performance, identifying root causes, and implementing corrective actions with precision. Our total recordable injury rate and lost time injury frequency rate decreased by 17 per cent and two per cent respectively.

While these results are positive and reflect significant effort across the organization to ensure everyone goes home safely every day, a workplace fatality at Tampa Electric in 2025 reinforces that we have more work to do. Our focus and efforts in this most critical aspect of our work needs to be relentless, as we work to achieve our goal of truly world class safety culture and performance.

Our responsibility to protect people also includes safeguarding the systems and information that support safe, reliable operations across our business. Cyber threats are becoming increasingly prevalent and sophisticated, targeting businesses of all types, including critical infrastructure. Unfortunately, in 2025, Nova Scotia Power experienced a cyber incident. The incident was managed through established response protocols in conjunction with relevant authorities, and the teams have worked tirelessly to restore the impacted systems. This incident has sharpened our focus on cybersecurity, informing ongoing improvements across the enterprise.

- Emera's 19th consecutive year of dividend growth in 2025 reflects the strength of our strategy and enduring commitment to responsible, long-term value creation.



Financial Results

Emera made company history this year by reporting annual adjusted net income⁽¹⁾ in excess of \$1 billion and adjusted EPS⁽¹⁾ of \$3.49—a 19 per cent increase over 2024. This was supported by strong performance at Tampa Electric, along with Emera Energy where favourable market conditions in the first and fourth quarters drove exceptional performance. We extended our \$20 billion capital plan through 2030 and advanced our largest annual capital program to date—roughly \$3.6 billion—focused on reinforcing reliability and resilience, advancing transmission upgrades, and integrating more renewables. We paced this investment to balance system needs with affordability impacts for customers—prioritizing reliability-driven projects, sequencing work to avoid cost spikes, and leveraging scale to lower long-term system costs.

This year, we also extended our adjusted EPS growth target of 5-7 per cent through 2030⁽²⁾, in line with our 7-8 per cent rate⁽²⁾ outlook over the same period. This reflects our confidence in the strength of our business, the resilience of our regulated portfolio, and sustained drivers of rate base growth.

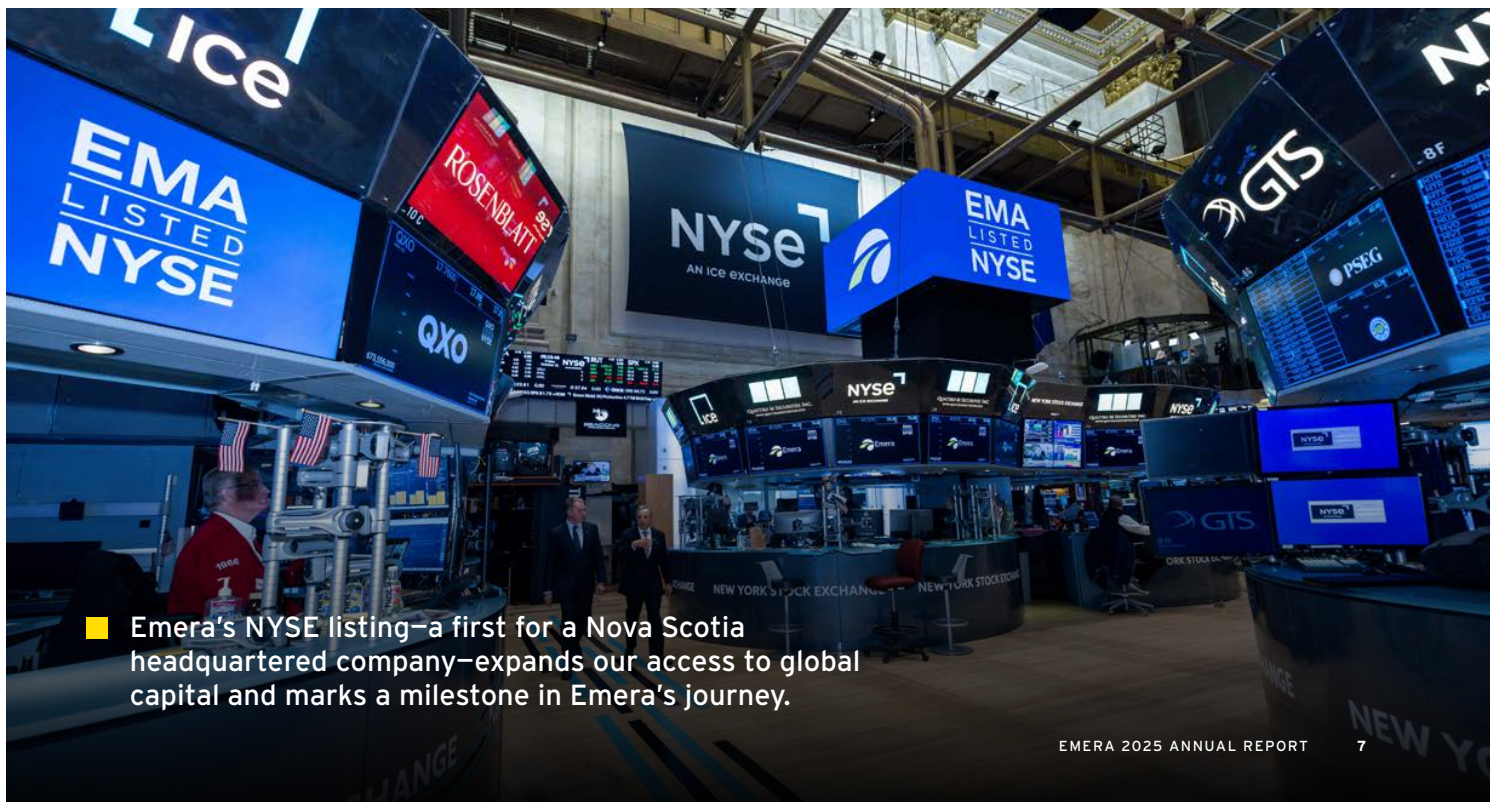
We continued to make progress on strengthening our balance sheet, with S&P and Fitch returning our investment grade credit ratings to stable in 2025. The Board also marked our 19th consecutive year of dividend growth, underscoring the strength of our business model and confidence in Emera's long-term earnings profile.

Strong execution also translated into strong shareholder returns. Emera's total shareholder return (TSR) was among the best in the industry at 31.9 per cent in 2025. Since March 29, 2018⁽³⁾ through December 31st 2025, Emera has delivered an average annual 12.1 per cent TSR—outperforming the S&P/TSX Capped Utilities Index (10.1 per cent) and the S&P US Utilities Index (11.2 per cent)—demonstrating our ability to deliver consistent shareholder value through multiple market cycles.

(1) Adjusted net income and adjusted EPS are a non-GAAP measure and non-GAAP ratio, respectively, which do not have standardized meaning under USGAAP. For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2025 MD&A.

(2) Uses 2024 as a base year.

(3) Date Scott Balfour became CEO.



■ Emera's NYSE listing—a first for a Nova Scotia headquartered company—expands our access to global capital and marks a milestone in Emera's journey.

Board Governance

The Board's disciplined oversight helped keep Emera focused on creating and delivering long-term value, balance sheet strength, and responsible growth as we advanced major investments. In a year marked by record performance and meaningful investment in reliability and clean energy, the Board remained actively engaged on strategy, enterprise risk, and capital allocation.

We welcomed Isabelle Courville to the Board in September 2025, who brings extensive director experience in both public and private sectors, along with a strong executive leadership track record. We would like to recognize that Brian Porter will not be standing for re-election at the 2026 AGM and would like to thank him for his service and contributions. We are also grateful for the service and dedication provided by Jackie Sheppard, who completed her transition from the Board in January 2026 after more than a decade of leadership.

Cybersecurity and digital resilience continued to be areas of focus for the Board this year. These types of threats—like the one at Nova Scotia Power—are becoming increasingly complex and challenging for organizations everywhere. Emera's Board continues to oversee cybersecurity practices across all operating companies, and this event reinforces the importance of vigilance in this matter. As Emera implements broader digital transformation efforts, including rapidly evolving areas such as AI governance and cybersecurity risk, the Board remains committed to thorough oversight to help guide these efforts and support system reliability, operational efficiency, and long-term resilience.

Thank You

The progress we achieved this year reflects the hard work, expertise, and discipline of teams across our business. Together, we delivered record financial results, advanced major investments in reliability and clean energy, strengthened our balance sheet, and maintained a sharp focus on providing value for customers.

With a strong foundation, a disciplined capital plan, and a premium portfolio of regulated utilities in high-quality jurisdictions, Emera is well-positioned for the opportunities ahead. We continue through 2026 with enduring momentum, a clear strategy, and confidence in our ability to continue delivering for our customers and our shareholders.

To the Board of Directors and the entire team at Emera, thank you for your dedication and focus throughout the year. Your commitment to serving customers and supporting shareholder value has been instrumental in achieving a landmark year, and we look forward to building on this momentum in the coming months.

To our valued shareholders, thank you for your continued confidence in Emera.



Karen Sheriff
Chair, Board of Directors,
Emera Inc.



Scott Balfour
President and Chief Executive Officer,
Emera Inc.

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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
Wasoqonati 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.

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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 four 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 distinguish ongoing operations of the business and allow 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 that 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.

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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.

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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
Net income ⁽¹⁾	\$ 87	\$ 173	\$ 1,090	\$ 568
Interest expense, net	268	248	1,032	973
Income tax (recovery) expense	(35)	(199)	81	(159)
Depreciation and amortization	335	296	1,294	1,162
EBITDA	\$ 655	\$ 518	\$ 3,497	\$ 2,544
MTM (loss) gain, excluding income tax	(138)	(203)	58	(408)
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

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

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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 the 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 the 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.

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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.

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For the millions of dollars	Three months ended December 31		Year ended December 31	
Adjusted net income	2025	2024	2025	2024
Florida Electric Utility	\$ 119	\$ 120	\$ 845	\$ 644
Canadian Electric Utilities	31	77	182	232
Gas Utilities and Infrastructure	76	87	276	267
Other Electric Utilities	15	21	43	48
Other	(74)	(59)	(301)	(342)
Adjusted net income	\$ 167	\$ 246	\$ 1,045	\$ 809
MTM (loss) gain, after-tax	(99)	(146)	41	(291)
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

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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	2024	Year ended December 31 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.

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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
Series B				\$ 0.9451	\$ 1.6966	\$ (0.7515)	\$ 1.5583
Series C				\$ 1.6085	\$ 1.6085	\$ –	\$ 1.2873
Series E				\$ 1.1250	\$ 1.1250	\$ –	\$ 1.1250
Series F				\$ 1.3406	\$ 1.0505	\$ 0.2900	\$ 1.0505
Series H				\$ 1.5810	\$ 1.5810	\$ –	\$ 1.3140
Series J				\$ 1.0625	\$ 1.0625	\$ –	\$ 1.0625
Series L				\$ 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.

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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; seven 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 one 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 that 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.

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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 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 licence to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licences 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") licences. The G&S licence will be valid until 2047, unless otherwise extended. The T&DLicence will be valid for 30 years. These new non-exclusive licences 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 Other 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.

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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 December 31		Year ended 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.

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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

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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

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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

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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.

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For the millions of USD (except as indicated)	Three months ended December 31		Year ended 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 December 31		Year ended 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 December 31	Year ended 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

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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.

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Other Electric Utilities

For the millions of USD (except as indicated)	Three months ended December 31		Year ended 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 December 31		Year ended 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 December 31	Year ended December 31
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.

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Other

For the millions of dollars	Three months ended December 31		Year ended 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 December 31		Year ended 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)

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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 the 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.

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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 December 31		Year ended 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).

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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.

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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.

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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.

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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.

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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

Issued and outstanding:	millions of shares	millions of dollars
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.

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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.

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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. For further details, 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.

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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.

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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 whom 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.

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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.

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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).

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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.

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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.

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Management Report

Management's Responsibility for Financial Reporting

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

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

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

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

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

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

February 23, 2026



"Scott Balfour"

President and Chief Executive Officer



"Jared Green"

Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion on the Consolidated Financial Statements

We have audited the accompanying Consolidated Balance Sheets of Emera Incorporated (the "Company") as of December 31, 2025 and 2024, the related Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2025 and 2024, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2025, in conformity with United States generally accepted accounting principles.

Basis for Opinion

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

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

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

Critical Audit Matters

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

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Accounting for the effects of rate regulation

Description of the Matter	As disclosed in note 7 of the consolidated financial statements, the Company has \$3.2 billion in regulatory assets and \$1.7 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including, but not limited to, property, plant and equipment ("PP&E"), operating revenues and expenses, income taxes, and depreciation expense. Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and return on costs incurred, of the potential disallowance of part of the cost incurred, or of the probable refund of gains or amounts previously collected from customers through future rates.
How We Addressed the Matter in Our Audit	We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, PP&E, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery or refund in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries, gains or amounts previously collected from customers or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

Fair Value ("FV") measurement of derivative financial instruments

Description of the Matter	Held-for-trading ("HFT") derivative assets of \$289 million and liabilities of \$745 million, disclosed in note 16 to the consolidated financial statements, are measured at FV. The Company recognized \$467 million in realized and unrealized gains during the year with respect to HFT derivatives. Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the FV of the contracts. In determining the FV of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials. These assumptions have a significant impact on the FV of the HFT derivatives.

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How We
Addressed the
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We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the FV hierarchy disclosures in note 17 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the FV of derivatives.

Ernst & Young LLP

Chartered Professional Accountants

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

Halifax, Canada

February 23, 2026

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Consolidated Statements of Income

For the millions of dollars (except per share amounts)	Year ended December 31	
	2025	2024
Operating revenues		
Regulated electric	\$ 6,858	\$ 5,872
Regulated gas	1,713	1,575
Non-regulated	205	(247)
Total operating revenues (note 6)	8,776	7,200
Operating expenses		
Regulated fuel for generation and purchased power	2,161	1,992
Regulated cost of natural gas	448	396
Operating, maintenance and general expenses ("OM&G")	2,337	1,918
Provincial, state, and municipal taxes	486	427
Depreciation and amortization	1,294	1,162
Impairment charges (note 4)	75	225
Total operating expenses	6,801	6,120
Income from operations	1,975	1,080
Income from equity investments (note 8)	63	99
Other income, net (note 9)	165	203
Interest expense, net (note 10)	1,032	973
Income before provision for income taxes	1,171	409
Income tax expense (recovery) (note 11)	81	(159)
Net income	1,090	568
Non-controlling interest in subsidiaries ("NCI")	1	1
Preferred stock dividends	75	73
Net income attributable to common shareholders	\$ 1,014	\$ 494
Weighted average shares of common stock outstanding (in millions) (note 13)		
Basic	299	289
Diluted	300	289
Earnings per common share (note 13)		
Basic	\$ 3.39	\$ 1.71
Diluted	\$ 3.38	\$ 1.71
Dividends per common share declared	\$ 2.9075	\$ 2.8775

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

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Consolidated Statements of Comprehensive Income

For the millions of dollars	Year ended December 31	
	2025	2024
Net income	\$ 1,090	\$ 568
Other comprehensive income (loss) ("OCI"), net of tax		
Foreign currency translation adjustment ⁽¹⁾	(623)	1,027
Unrealized gains (losses) on net investment hedges ⁽²⁾	82	(139)
Cash flow hedges - reclassification adjustment for gains included in income	(2)	(2)
Unrealized gains on available-for-sale investment	2	2
Net change in unrecognized pension and post-retirement benefit obligation ⁽³⁾	153	68
OCI ⁽⁴⁾	(388)	956
Comprehensive income	702	1,524
Comprehensive income attributable to NCI	1	1
Comprehensive Income of Emera Incorporated	\$ 701	\$ 1,523

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

- 1) Net of tax recovery of \$5 million for the year ended December 31, 2025 (2024 - \$10 million expense).
- 2) The Company has designated \$1.2 billion United States dollar (USD) denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations.
- 3) Net of tax expense of \$3 million for the year ended December 31, 2025 (2024 - nil).
- 4) Net of tax recovery of \$2 million for the year ended December 31, 2025 (2024 - \$10 million expense).

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Consolidated Balance Sheets

As at millions of dollars	December 31 2025	December 31 2024
Assets		
Current assets		
Cash and cash equivalents	\$ 349	\$ 196
Restricted cash	16	17
Inventory (note 15)	821	781
Derivative instruments (notes 16 and 17)	156	115
Regulatory assets (note 7)	409	595
Receivables and other current assets (note 19)	2,439	1,811
Assets held for sale (note 4)	199	173
	4,389	3,688
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of \$10,845 and \$10,442, respectively (note 21)	27,408	26,168
Other assets		
Deferred income taxes (note 11)	421	392
Derivative instruments (notes 16 and 17)	42	51
Regulatory assets (note 7)	2,789	2,832
Net investment in direct finance and sales type leases (note 20)	572	610
Investments subject to significant influence (note 8)	634	654
Goodwill (note 23)	5,580	5,858
Other long-term assets (note 33)	894	538
Assets held for sale (note 4)	2,088	2,160
	13,020	13,095
Total assets	\$ 44,817	\$ 42,951

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

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Consolidated Balance Sheets (continued)

As at millions of dollars	December 31 2025	December 31 2024
Liabilities and Equity		
Current liabilities		
Short-term debt (note 24)	\$ 1,807	\$ 1,400
Current portion of long-term debt (note 26)	1,201	234
Accounts payable	1,948	1,992
Derivative instruments (notes 16 and 17)	534	526
Regulatory liabilities (note 7)	211	262
Other current liabilities (note 25)	535	489
Liabilities associated with assets held for sale (note 4)	391	212
	6,627	5,115
Long-term liabilities		
Long-term debt (note 26)	18,453	18,173
Deferred income taxes (note 11)	2,516	2,331
Derivative instruments (notes 16 and 17)	115	91
Regulatory liabilities (note 7)	1,458	1,618
Pension and post-retirement liabilities (note 22)	268	274
Other long-term liabilities (note 8 and 27)	960	910
Liabilities associated with assets held for sale (note 4)	1,024	1,148
	24,794	24,545
Equity		
Common stock (note 12)	9,387	9,042
Cumulative preferred stock (note 29)	1,422	1,422
Contributed surplus	86	84
Accumulated other comprehensive income ("AOCI") (note 14)	873	1,261
Retained earnings	1,614	1,468
Total Emera Incorporated equity	13,382	13,277
NCI (note 30)	14	14
Total equity	13,396	13,291
Total liabilities and equity	\$ 44,817	\$ 42,951

Commitments and contingencies (note 28)

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

Approved on behalf of the Board of Directors



"Karen Sheriff"
Chair of the Board



"Scott Balfour"
President and Chief Executive Officer

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Consolidated Statements of Cash Flows

For the millions of dollars	Year ended December 31	
	2025	2024
Operating activities		
Net income	\$ 1,090	\$ 568
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	1,298	1,165
Income from equity investments, net of dividends	5	(8)
Allowance for funds used during construction ("AFUDC") - equity	(62)	(53)
Deferred income taxes, net	71	(191)
Net change in pension and post-retirement liabilities	(40)	(46)
Nova Scotia Power ("NSPI") fuel adjustment mechanism ("FAM")	(158)	451
Net change in fair value ("FV") of derivative instruments	13	228
Net change in regulatory assets and liabilities	296	(226)
Net change in capitalized transportation capacity	(65)	175
Impairment charges	75	214
Gain on sale of the Labrador Island Link Partnership ("LIL"), excluding transaction costs	(4)	(191)
Other operating activities, net	40	108
Changes in non-cash working capital (note 31)	(757)	452
Net cash provided by operating activities	1,802	2,646
Investing activities		
Additions to PP&E	(3,532)	(3,151)
Proceeds on disposal of assets	48	7
Proceeds from disposal of investment subject to significant influence	—	927
Other investing activities	2	(1)
Net cash used in investing activities	(3,482)	(2,218)
Financing activities		
Change in short-term debt, net	(78)	56
Proceeds from short-term debt with maturities greater than 90 days	598	—
Proceeds from long-term debt, net of issuance costs	2,016	1,361
Retirement of long-term debt	(201)	(1,086)
Net proceeds (repayments) under committed credit facilities	119	(825)
Issuance of common stock, net of issuance costs	47	284
Dividends on common stock	(576)	(538)
Dividends on preferred stock	(75)	(73)
Other financing activities	(9)	3
Net cash provided by (used in) financing activities	1,841	(818)
Effect of exchange rate changes on cash, cash equivalents, restricted cash and cash associated with assets held for sale	(11)	23
Net increase (decrease) in cash, cash equivalents, restricted cash and cash associated with assets held for sale	150	(367)
Cash, cash equivalents, restricted cash, and cash associated with assets held for sale, beginning of year	221	588
Cash, cash equivalents, restricted cash, and cash associated with assets held for sale, end of year	\$ 371	\$ 221
Cash, cash equivalents, restricted cash and cash associated with assets held for sale consists of:		
Cash	\$ 344	\$ 191
Short-term investments	5	5
Restricted cash	16	17
Cash associated with assets held for sale	6	8
Cash, cash equivalents, restricted cash and cash associated with assets held for sale	\$ 371	\$ 221

Supplementary Information to Consolidated Statements of Cash Flows (note 31)

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

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Consolidated Statements of Changes in Equity

millions of dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	NCI	Total Equity
Balance, December 31, 2024	\$ 9,042	\$ 1,422	\$ 84	\$ 1,261	\$ 1,468	\$ 14	\$ 13,291
Net income of Emera Inc.	—	—	—	—	1,089	1	1,090
Other comprehensive loss, net of tax recovery of \$2 million	—	—	—	(388)	—	—	(388)
Dividends declared on preferred stock (note 29)	—	—	—	—	(75)	—	(75)
Dividends declared on common stock (\$2.9075/share)	—	—	—	—	(868)	—	(868)
Issued under the at-the-market program ("ATM"), net of after-tax issuance costs	9	—	—	—	—	—	9
Issued under the Dividend Reinvestment Program ("DRIP"), net of discount	293	—	—	—	—	—	293
Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSP")	42	—	2	—	—	—	44
Other	1	—	—	—	—	(1)	—
Balance, December 31, 2025	\$ 9,387	\$ 1,422	\$ 86	\$ 873	\$ 1,614	\$ 14	\$ 13,396
Balance, December 31, 2023	\$ 8,462	\$ 1,422	\$ 82	\$ 305	\$ 1,803	\$ 14	\$ 12,088
Net income of Emera Inc.	—	—	—	—	567	1	568
Other comprehensive income, net of tax expense of \$10 million	—	—	—	956	—	—	956
Dividends declared on preferred stock (note 29)	—	—	—	—	(73)	—	(73)
Dividends declared on common stock (\$2.8775/share)	—	—	—	—	(829)	—	(829)
Issued under the ATM, net of after-tax issuance costs	261	—	—	—	—	—	261
Issued under the DRIP, net of discount	291	—	—	—	—	—	291
Senior management stock options exercised and ECSP	28	—	2	—	—	—	30
Other	—	—	—	—	—	(1)	(1)
Balance, December 31, 2024	\$ 9,042	\$ 1,422	\$ 84	\$ 1,261	\$ 1,468	\$ 14	\$ 13,291

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

Notes to the Consolidated Financial Statements

As at December 31, 2025 and 2024

1. Summary of Significant Accounting Policies

Nature of Operations

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

At December 31, 2025, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), a vertically integrated regulated electric utility, serving approximately 866,000 customers in West Central Florida.
- Canadian Electric Utilities, which includes:
 - NSPI, a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 565,000 customers;
 - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a \$1.8 billion, including AFUDC, transmission project between the island of Newfoundland and Nova Scotia; and
 - a 50 per cent indirect voting equity interest in Wasoqonatl Transmission Incorporated ("WTI"), a transmission line project to create a reliability intertie between Nova Scotia and New Brunswick. For more information, refer to note 8.
- Gas Utilities and Infrastructure, which includes:
 - Peoples Gas System Inc. ("PGS"), a regulated gas distribution utility, serving approximately 523,000 customers across Florida;
 - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 553,000 customers in New Mexico. On August 5, 2024, Emera announced an agreement to sell NMGC. The transaction is expected to close in the first half of 2026, subject to certain approvals, including approval by the New Mexico Public Regulation Commission ("NMPRC"). For more information on the pending transaction, refer to note 4.
 - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States ("US") border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership ("Repsol Energy Canada"), which expires in 2034;
 - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida; and
 - a 12.9 per cent equity interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline that transports natural gas throughout markets in Atlantic Canada and the northeastern US.
- Other Electric Utilities, which includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities that include:
 - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated regulated electric utility on the island of Barbados, serving approximately 137,000 customers;
 - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 20,000 customers; and
 - a 19.5 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

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- Emera's other segment includes investments in energy-related non-regulated companies that are below the required threshold for reporting as separate segments and corporate expense and revenue items that are not directly allocated to the operations of Emera's subsidiaries and investments. This includes:
 - Emera Energy, which consists of:
 - Emera Energy Services ("EES"), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
 - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; and
 - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts.
 - Emera US Finance LP ("Emera Finance"), EUSHI Finance, Inc. ("EUSHI Finance") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
 - Emera US Holdings Inc. ("EUSHI"), a wholly owned holding company for certain of Emera's assets located in the US; and
 - Other investments.

Basis of Presentation

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

All dollar amounts are presented in Canadian dollars ("CAD"), unless otherwise indicated.

Principles of Consolidation

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

The Company performs ongoing analysis to assess whether it holds any VIEs or whether any reconsideration events have arisen with respect to existing VIEs. To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the VIE that most significantly impacts its economic performance and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. In circumstances where Emera has an investment in a VIE but is not deemed the primary beneficiary, the VIE is accounted for using the equity method. For further details on VIEs, refer to note 33.

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

Use of Management Estimates

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

Regulatory Matters

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

Foreign Currency Translation

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

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

The Company designates certain USD denominated debt held in CAD functional currency companies as hedges of net investments in USD denominated foreign operations. The change in the carrying amount of these investments, measured at exchange rates in effect at the balance sheet date, is recorded in OCI.

Revenue Recognition

Regulated Electric and Gas Revenue:

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

Non-regulated Revenue:

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

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

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

Other:

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

Franchise Fees and Gross Receipts

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

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

Notes to the Consolidated Financial Statements

PP&E

PP&E is recorded at original cost, including AFUDC or capitalized interest, net of contributions received in aid of construction.

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

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

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

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

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

Goodwill

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

If the Company performs a qualitative assessment and determines it is more likely than not that its FV is less than its carrying amount, or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the FV of the reporting unit to its carrying value, including goodwill ("carrying amount"). If the carrying amount of the reporting unit exceeds its FV, an impairment loss is recorded. Management estimates the FV of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach uses a discounted cash flow analysis which relies on management's best estimate of the reporting unit's projected cash flows. The analysis includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the reporting unit's residual cash flows. The discount rate used is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. For the market approach, management estimates FV based on comparable companies and transactions within comparable industries, or in the case of the NMGC quantitative assessment in 2024, transactions involving the reporting unit. Significant assumptions used in estimating the FV of a reporting unit using an income approach include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting unit's net operating loss ("NOL") and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera's reporting units.

As of December 31, 2025, Emera's goodwill represented 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 Q4 2025, qualitative assessments were 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.

Income Taxes and Investment and Production Tax Credits

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

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

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

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. For further details, refer to note 11.

Derivatives and Hedging Activities

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.

Notes to the Consolidated Financial Statements

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.

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

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

Leases

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

Lease liabilities and right-of-use assets are recognized on the Consolidated Balance Sheets based on the present value of the future minimum lease payments over the lease term at commencement date. As most of Emera's leases do not provide an implicit rate, the incremental borrowing rate at commencement of the lease is used in determining the present value of future lease payments. For operating leases, expense is recognized on a straight-line basis over the lease term and is recorded as "OM&G" on the Consolidated Statements of Income. For finance leases, the amortization of the ROU asset is recorded as "Depreciation and amortization expense" and the interest on lease liabilities is recorded as "Interest expense, net" on the Consolidated Statements of Income.

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

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

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

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

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

Cash, Cash Equivalents and Restricted Cash

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

Receivables and Allowance for Credit Losses

Utility customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date. The Company recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Management estimates credit losses related to accounts receivable by considering historical loss experience, customer deposits, current events, the characteristics of existing accounts and reasonable and supportable forecasts that affect the collectability of the reported amount. Provisions for credit losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

Inventory

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

Asset Impairment

Long-Lived Assets:

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

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

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 Statements of Income. 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.

Equity Method Investments:

The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the FV of these investments to their carrying values, if a FV assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists, and it is determined to be other-than-temporary, a charge is recognized in earnings equal to the amount the carrying value exceeds the investment's FV. No impairment of equity method investments was required in either 2025 or 2024.

Financial Assets:

Equity investments, other than those accounted for under the equity method, are measured at FV, with changes in FV recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable FV are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments. No impairment of financial assets was required in either 2025 or 2024.

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Asset Retirement Obligations

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

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

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

Cost of Removal ("COR")

TEC, PGS, NMGC and NSPI recognize non-ARO COR as regulatory liabilities or regulatory assets. The non-ARO COR represent funds received from customers through depreciation rates to cover estimated future non-legally required COR of PP&E upon retirement. The companies accrue for COR over the life of the related assets based on depreciation studies approved by their respective regulators. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays.

Stock-Based Compensation

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

Employee Benefits

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes unamortized gains and losses and past service costs in "AOCI" or "Regulatory assets" on the Consolidated Balance Sheets. The components of net periodic benefit cost other than the service cost component are included in "Other income, net" on the Consolidated Statements of Income. For further details, refer to note 22.

Government Grants

The Company accounts for government grants by applying a grant accounting model by analogy to International Accounting Standards ("IAS") 20, *Accounting for Government Grants and Disclosure of Government Assistance*. A grant relating to an asset is reflected in the determination of the carrying amount of the asset. A grant relating to income is presented as a deduction from the related expense it is intended to compensate.

In 2025, the Company received an aggregate of \$80 million (2024 - \$47 million) of government grants from various Canadian and US government agencies towards capital projects included in PP&E. The capital projects receiving grants primarily relate to the Company's decarbonization and environmental compliance initiatives. Further details on significant grant programs utilized in 2025 and 2024 are noted below.

Natural Resources Canada ("NRCan") Smart Renewables & Electrification Pathways ("SREP"):

On March 27, 2024, NSPI was approved for a grant under the NRCan SREPs to fund the construction of three 50 MW battery storage systems in Nova Scotia. NSPI can make claims under the grant for 33 per cent of eligible project costs to a maximum \$109 million. Eligible costs can be incurred until March 31, 2027. For the year-end December 31, 2025, NSPI received \$45 million (2024 - \$26 million) in funding under the grant, which has been recorded as a reduction to the carrying amount of the project in PP&E.

Cybersecurity Incident

On April 25, 2025, Emera and NSPI discovered a cybersecurity incident (the "Cybersecurity Incident") involving unauthorized access into certain parts of its Canadian IT network and servers supporting portions of its business applications. There was no disruption to the Canadian physical operations or to 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. The Company maintains cyber insurance coverage and is working with its insurer on the claims process.

2. Change in Accounting Policy

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.

3. 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.

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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.

4. Dispositions

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.

As the transaction proceeds will be lower than the carrying amount of the assets and liabilities being sold, in Q3 2024 Emera assessed the NMGC reporting unit for goodwill impairment by comparing the FV of expected transaction proceeds to the carrying value of net assets, including goodwill of \$366 million USD. The goodwill of the reporting unit was determined to be impaired and a non-cash goodwill impairment charge of \$210 million (\$198 million, after-tax), or \$155 million USD (\$146 million USD, after-tax), was recorded in "Impairment charges" on the Consolidated Statements of Income in Q3 2024.

Following the goodwill impairment assessment, the held for sale assets and liabilities were measured at the lower of their carrying amount or fair value less costs to sell. The measurement resulted in an additional loss for the estimated future transaction costs of \$16 million (\$12 million after-tax), in addition to incurred transaction costs of \$9 million (\$7 million after-tax) recorded in "Other Income, net" on the Consolidated Statements of Income in Q3 2024.

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.

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Details of the assets and liabilities classified as held for sale are as follows:

As at millions of dollars	December 31 2025	December 31 2024
Cash and cash equivalents	\$ 6	\$ 8
Inventory	10	9
Derivative instruments	—	1
Regulatory assets	41	28
Receivables and other current assets	142	127
Current assets held for sale	\$ 199	\$ 173
PP&E	1,856	1,845
Regulatory assets	4	6
Goodwill	289	303
Other long-term assets	28	23
Less: Adjustment to FV less costs to sell ⁽¹⁾	(89)	(17)
Long-term assets held for sale	\$ 2,088	\$ 2,160
Total assets held for sale	\$ 2,287	\$ 2,333
Short-term debt	\$ 116	\$ 46
Current portion of long-term debt	96	—
Derivative instruments	—	1
Regulatory liabilities	25	10
Accounts payable and other current liabilities	154	155
Current liabilities associated with assets held for sale	391	212
Long-term debt	567	696
Deferred income taxes	185	167
Regulatory liabilities	261	274
Other long-term liabilities	11	11
Long-term liabilities associated with assets held for sale	\$ 1,024	\$ 1,148
Total liabilities associated with assets held for sale	\$ 1,415	\$ 1,360

(1) Represents a \$75 million impairment charge related to the remeasurement of the NMGC disposal group to FV (December 31, 2024 - nil) and \$14 million in estimated transaction costs related to the pending sale (December 31, 2024 - \$17 million).

Sale of LIL Equity Interest

On June 4, 2024, Emera completed the sale of its 31.1 per cent indirect minority equity interest in the LIL for a total transaction value of \$1.2 billion, including cash proceeds of \$957 million and \$235 million for assuming Emera's contractual obligation to fund the remaining initial capital investment, which represents additional LIL equity interest for the acquirer. Cash proceeds from the sale in the amount of \$30 million is held in escrow pending finalization of certain agreements with the LIL general partner. The escrow proceeds receivable is held at FV and included in the gain on sale, after transaction costs. As of December 31, 2025, the estimated FV of the escrow proceeds receivable was \$29 million. In Q2 2024, a gain on sale, after transaction costs, of \$182 million (\$107 million, after tax and transaction costs), was recognized in "Other income, net" on the Consolidated Statements of Income and included in the Other segment. In Q4 2024, Emera recognized an incremental \$22 million tax benefit related to loss carryforwards applied against the taxable capital gain on the sale.

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5. Segment Information

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

For the Company's reportable segments, the CODM uses several measures to allocate capital and resources for each segment, predominantly in the annual budget and forecasting processes. The CODM evaluates segment performance by considering budget-to-actual variances for these measures monthly. The measure used by the CODM that is the most consistent with USGAAP measurement principles is net income attributable to common shareholders.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter- Segment Eliminations	Total
For the year ended December 31, 2025							
Operating revenues from external customers ⁽¹⁾	\$ 4,336	\$ 1,944	\$ 1,737	\$ 577	\$ 182	\$ –	\$ 8,776
Inter-segment revenues ⁽¹⁾	10	–	19	–	24	(53)	–
Total operating revenues	4,346	1,944	1,756	577	206	(53)	8,776
Regulated fuel for generation and purchased power	982	904	–	294	–	(19)	2,161
Regulated cost of natural gas	–	–	448	–	–	–	448
OM&G	1,135	457	491	145	140	(31)	2,337
Provincial, state and municipal taxes	318	49	114	4	1	–	486
Depreciation and amortization	705	298	207	78	6	–	1,294
Impairment charges	–	–	–	–	75	–	75
Income (loss) from equity investments	–	41	18	5	(1)	–	63
Other income, net	84	32	9	7	30	3	165
Interest expense, net ⁽²⁾	305	172	149	21	385	–	1,032
Income tax expense (recovery)	140	(45)	98	3	(115)	–	81
NCI in subsidiaries	–	–	–	1	–	–	1
Preferred stock dividends	–	–	–	–	75	–	75
Net income (loss) attributable to common shareholders	\$ 845	\$ 182	\$ 276	\$ 43	\$ (332)	\$ –	\$ 1,014
Capital expenditures	\$ 2,153	\$ 630	\$ 619	\$ 94	\$ 6	\$ –	\$ 3,502
As at December 31, 2025							
Total assets	\$ 24,636	\$ 8,546	\$ 8,476	\$ 1,439	\$ 2,469	\$ (749)	\$ 44,817
Investments subject to significant influence	\$ –	\$ 471	\$ 108	\$ 55	\$ –	\$ –	\$ 634
Goodwill	\$ 4,796	\$ –	\$ 784	\$ –	\$ –	\$ –	\$ 5,580

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

(2) Segment net income is reported on a basis that includes internally allocated financing costs of \$27 million for the year ended December 31, 2025, between the Gas Utilities and Infrastructure and Other segments.

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millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the year ended December 31, 2024							
Operating revenues from external customers ⁽¹⁾	\$ 3,451	\$ 1,855	\$ 1,595	\$ 566	\$ (267)	\$ –	\$ 7,200
Inter-segment revenues ⁽¹⁾	9	–	14	–	19	(42)	–
Total operating revenues	3,460	1,855	1,609	566	(248)	(42)	7,200
Regulated fuel for generation and purchased power	852	859	–	295	–	(14)	1,992
Regulated cost of natural gas	–	–	396	–	–	–	396
OM&G	779	408	454	143	154	(20)	1,918
Provincial, state and municipal taxes	273	48	103	3	–	–	427
Depreciation and amortization	622	282	182	69	7	–	1,162
Impairment charge	–	–	11	–	214	–	225
Income from equity investments	–	73	20	4	2	–	99
Other income, net	66	28	16	12	73	8	203
Interest expense, net ⁽²⁾	265	168	151	22	367	–	973
Income tax expense (recovery)	94	(41)	89	1	(302)	–	(159)
NCI in subsidiaries	–	–	–	1	–	–	1
Preferred stock dividends	–	–	–	–	73	–	73
Net income (loss) attributable to common shareholders	\$ 641	\$ 232	\$ 259	\$ 48	\$ (686)	\$ –	\$ 494
Capital expenditures	\$ 1,942	\$ 481	\$ 619	\$ 81	\$ 4	\$ –	\$ 3,127
As at December 31, 2024							
Total assets	\$ 24,375	\$ 7,609	\$ 8,439	\$ 1,444	\$ 1,810	\$ (726)	\$ 42,951
Investments subject to significant influence	\$ –	\$ 475	\$ 124	\$ 55	\$ –	\$ –	\$ 654
Goodwill	\$ 5,035	\$ –	\$ 823	\$ –	\$ –	\$ –	\$ 5,858

- (1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.
- (2) Segment net income is reported on a basis that includes internally allocated financing costs of \$29 million for the year ended December 31, 2024, between the Gas Utilities and Infrastructure and Other segments.

Geographical Information

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

For the millions of dollars	Year ended December 31	
	2025	2024
United States	\$ 6,185	\$ 4,712
Canada	2,014	1,922
Barbados	415	427
The Bahamas	162	139
	\$ 8,776	\$ 7,200

PP&E:

As at millions of dollars	December 31 2025	December 31 2024
United States ⁽¹⁾	\$ 20,931	\$ 20,084
Canada	5,476	5,068
Barbados	640	645
The Bahamas	361	371
	\$ 27,408	\$ 26,168

- (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 and excluded from the table above beginning in Q3 2024. For further details on the pending transaction, refer to note 4.

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6. Revenue

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

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Electric Other Electric Utilities	Gas Utilities and Infrastructure	Other	Other Inter- Segment Eliminations	Total
For the year ended December 31, 2025							
Regulated Revenue							
Residential	\$ 2,489	\$ 1,073	\$ 201	\$ 770	\$ –	\$ –	\$ 4,533
Commercial	1,147	522	308	528	–	–	2,505
Industrial	272	270	28	102	–	(19)	653
Other electric	457	43	7	–	–	–	507
Regulatory deferrals	(41)	–	21	–	–	–	(20)
Other ⁽¹⁾	22	36	12	269	–	(10)	329
Finance income ⁽²⁾⁽³⁾	–	–	–	64	–	–	64
Regulated revenue	\$ 4,346	\$ 1,944	\$ 577	\$ 1,733	\$ –	\$ (29)	\$ 8,571
Non-Regulated Revenue							
Marketing and trading margin ⁽⁴⁾	–	–	–	–	158	–	158
Other non-regulated operating revenue	–	–	–	23	32	(25)	30
Mark-to-market ⁽³⁾	–	–	–	–	16	1	17
Non-regulated revenue	\$ –	\$ –	\$ –	\$ 23	\$ 206	\$ (24)	\$ 205
Total operating revenues	\$ 4,346	\$ 1,944	\$ 577	\$ 1,756	\$ 206	\$ (53)	\$ 8,776
For the year ended December 31, 2024							
Regulated Revenue							
Residential	\$ 2,063	\$ 997	\$ 203	\$ 712	\$ –	\$ –	\$ 3,975
Commercial	939	499	300	496	–	–	2,234
Industrial	223	276	28	94	–	(14)	607
Other electric	372	41	7	–	–	–	420
Regulatory deferrals	(157)	–	15	–	–	–	(142)
Other ⁽¹⁾	20	42	13	224	–	(9)	290
Finance income ⁽²⁾⁽³⁾	–	–	–	63	–	–	63
Regulated revenue	\$ 3,460	\$ 1,855	\$ 566	\$ 1,589	\$ –	\$ (23)	\$ 7,447
Non-Regulated							
Marketing and trading margin ⁽⁴⁾	–	–	–	–	77	–	77
Other non-regulated operating revenue	–	–	–	20	32	(24)	28
Mark-to-market ⁽³⁾	–	–	–	–	(357)	5	(352)
Non-regulated revenue	\$ –	\$ –	\$ –	\$ 20	\$ (248)	\$ (19)	\$ (247)
Total operating revenues	\$ 3,460	\$ 1,855	\$ 566	\$ 1,609	\$ (248)	\$ (42)	\$ 7,200

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

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

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

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

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Remaining Performance Obligations:

Remaining performance obligations primarily represent gas transportation contracts, and long-term steam supply arrangements with fixed contract terms. As of December 31, 2025, the aggregate amount of the transaction price allocated to remaining performance obligations was \$344 million (2024 - \$495 million), including \$11 million related to NMGC. This amount includes \$121 million of future performance obligations related to a gas transportation contract between SeaCoast and PGS through 2040, and \$21 million of future performance obligations related to asset management agreements between PGS and EES through 2030. This amount excludes contracts with an original expected length of one year or less and variable amounts for which Emera recognizes revenue at the amount to which it has the right to invoice for services performed. Emera expects to recognize revenue for the remaining performance obligations through 2040.

7. Regulatory Assets and Liabilities

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

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

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

As at millions of dollars	December 31 2025 ⁽¹⁾	December 31 2024 ⁽¹⁾
Regulatory assets		
Deferred income tax regulatory assets	\$ 1,385	\$ 1,227
TEC capital cost recovery for early retired assets	727	737
Pension and post-retirement medical plan	316	395
Storm cost recovery clauses	206	613
TEC capital cost recovery for retired Polk Unit 1 components	178	205
NSPI FAM	102	—
Cost recovery clauses	55	33
Deferrals related to derivative instruments	36	42
Environmental remediations	27	29
Stranded cost recovery	25	27
Other ⁽²⁾	141	119
	\$ 3,198	\$ 3,427
Current	\$ 409	\$ 595
Long-term	2,789	2,832
Total regulatory assets	\$ 3,198	\$ 3,427
Regulatory liabilities		
Deferred income tax regulatory liabilities	751	828
Accumulated reserve - COR	729	733
Cost recovery clauses	75	121
BLPC Self-insurance fund ("SIF") (note 33)	30	32
Deferrals related to derivative instruments	25	44
NSPI FAM	—	56
Other ⁽²⁾	59	66
	\$ 1,669	\$ 1,880
Current	\$ 211	\$ 262
Long-term	1,458	1,618
Total regulatory liabilities	\$ 1,669	\$ 1,880

(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 and excluded from the table above. For further details on the pending transaction, refer to note 4.

(2) Comprised of regulatory assets and liabilities that are not individually significant.

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Deferred Income Tax Regulatory Assets and Liabilities

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

TEC Capital Cost Recovery for Early Retired Assets

Represents the remaining net book value of Big Bend Power Station Units 1 through 3 and smart meter assets that were early retired. The balance earns a rate of return as permitted by the FPSC and is being recovered as a separate line item on customer bills for a period of 15 years, beginning in January 2022.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at TEC and PGS. Deferred costs of post-retirement benefits that are included in expense are recognized as cost of service for rate-making purposes as permitted by the FPSC, as applicable and amortized over the remaining service life of plan participants.

Storm Cost Recovery Clauses

TEC and PGS Storm Reserve:

The storm reserve is for hurricanes and other named storms that cause significant damage to TEC and PGS systems. As allowed by the FPSC, if charges to the storm reserve exceed the storm reserve liability, the excess is to be carried as a regulatory asset. TEC and PGS can petition the FPSC to seek recovery of restoration costs over a 12-month period or longer, as determined by the FPSC, as well as replenish the reserve.

NSPI Storm Rider:

NSPI has a NSEB approved storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the NSEB for recovery of costs if major storm restoration expense exceeds approximately \$10 million in a given year. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application.

GBPC Storm Restoration:

This asset includes storm restoration costs incurred by GBPC related to Hurricane Dorian in 2020 and Hurricane Matthew in 2016. The Hurricane Matthew asset was fully amortized at the end of 2024.

TEC Capital Cost Recovery for Retired Polk Unit 1 Components

This regulatory asset relates to the remaining net book value of certain components of Polk Unit 1 that were early retired on December 31, 2024. The balance earns a rate of return as permitted by the FPSC and are being recovered through base rates over an 11-year recovery period beginning on January 1, 2025.

NSPI FAM

NSPI has a NSEB approved FAM, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

Cost Recovery Clauses

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

Deferrals Related to Derivative Instruments

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

Environmental Remediations

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

Stranded Cost Recovery

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

Accumulated Reserve – COR

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

Regulatory Environments and Updates

Florida Electric Utility

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

TEC's approved regulated return on equity ("ROE") range for 2025 was 9.50 per cent to 11.50 per cent (2024 - 9.25 per cent to 11.25 per cent) based on an allowed equity capital structure of 54 per cent. An ROE of 10.50 per cent (2024 - 10.20 per cent) is used for the calculation of the return on investments for clauses.

Base Rates:

On April 2, 2024, TEC filed a rate case with the FPSC for new base rates. On December 3, 2024, the FPSC rendered a decision which included annual base rate increases of \$185 million USD in 2025 and adjustments of \$87 million USD and \$9 million USD in 2026 and 2027, respectively. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital and the allowed regulatory ROE range is 9.50 per cent to 11.50 per cent with a 10.50 per cent midpoint. On February 3, 2025, the FPSC issued the final order approving the rate case decision, effective January 1, 2025. 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 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.

Fuel Recovery and Other Cost Recovery Clauses:

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

On April 2, 2024, TEC requested a mid-course adjustment to its fuel and capacity charges, reflecting a \$138 million USD reduction over 12 months, from June 2024 through May 2025. The requested reduction was due to a decrease in actual and projected 2024 natural gas prices since TEC submitted its projected 2024 costs in the fall of 2023. On May 7, 2024, the FPSC approved the mid-course adjustment.

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Storm Reserve:

On February 4, 2025, the FPSC approved TEC's petition for the recovery of \$466 million USD for 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 beginning March 2025. The amount of cost-recovery is subject to a true-up mechanism with the FPSC.

Canadian Electric Utilities

NSPI

NSPI is a public utility as defined in the *Public Utilities Act* of Nova Scotia ("Public Utilities Act") and is subject to regulation by the NSEB. The Public Utilities Act gives the NSEB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to NSEB approval. NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide a reasonable return to investors. NSPI 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.

NSPI's approved regulated ROE range for 2025 and 2024 was 8.75 per cent to 9.25 per cent based on an actual five quarter average regulated common equity component of up to 40 per cent of approved rate base.

General Rate Application ("GRA"):

On September 18, 2025, NSPI filed a consensus General Rate Application ("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.

Federal Loan Guarantee ("FLG"):

On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSPML and the Province of Nova Scotia (the "Province") on terms and conditions for a FLG of \$500 million in debt to be issued by NSPML to help Nova Scotia customers manage unrecovered costs of the replacement energy that was required during the several years of delay in the Muskrat Falls hydroelectricity project. On November 29, 2024, the NSEB approved NSPML's application to issue the debt, transfer the proceeds to NSPI as a refund of a portion of previous NSPML assessment payments, and increase its annual assessment charge to NSPI to recover the refund and related financing costs over a 28-year period. On December 16, 2024, the net proceeds of the NSPML debt issuance were transferred to NSPI and applied against the FAM regulatory asset balance.

FAM Asset Sale:

On April 17, 2024, the NSEB approved the sale of \$117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the \$117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. NSPI is collecting the amortization and financing costs related to the \$117 million from customers on behalf of Invest Nova Scotia over a 10-year period which began in Q2 2024 and is remitting those amounts to Invest Nova Scotia quarterly.

Storm Rider:

On December 2, 2024, the NSEB approved the recovery of \$24 million of major storm restoration and incremental financing costs deferred to NSPI's storm rider in 2023 to be recovered over a 12-month period beginning on January 1, 2025.

Hurricane Fiona:

NSPI has NSEB approved regulatory assets for the deferred recognition of \$25 million in incremental operating costs incurred during the Hurricane Fiona storm restoration efforts, and \$10 million of undepreciated costs related to assets retired, because of Hurricane Fiona in September 2022. Beginning on July 1, 2024, these regulatory assets are being amortized over a 10-year period.

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.

Newfoundland and Labrador Hydro's ("NLH") Nova Scotia Block ("NS Block") delivery obligations commenced in 2021 and delivery will continue over the next 35 years pursuant to the 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.

On February 4, 2026, NSPML submitted an application with the NSEB requesting the termination of the holdback mechanism.

On September 24, 2024, the Government of Canada finalized an agreement with NSPI, NSPML, and the Province on terms and conditions for a FLG of \$500 million in debt to be issued by NSPML. For further information, refer to the NSPI section above.

On November 29, 2024, NSPML received approval from the NSEB to collect up to \$197 million in 2025 from NSPI, which included \$158 million for the recovery of costs associated with the Maritime Link, and \$39 million associated with the additional FLG debt and financing costs noted in the NSPI section above. Payments from NSPI were subject to a holdback of up to \$4 million per month. There was no holdback recorded for the year ended December 31, 2025 (2024 - nil).

Gas Utilities and Infrastructure

PGS

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

PGS's approved ROE range for 2025 and 2024 was 9.15 per cent to 11.15 per cent with a 10.15 per cent midpoint, based on an allowed equity capital structure of 54.7 per cent.

Base Rates:

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.

Fuel Recovery:

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

Recovery of Energy Conservation and Pipeline Replacement Programs:

The FPSC annually approves a conservation charge that is intended to permit PGS to recover prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are required by Florida law and approved and monitored by the FPSC. PGS also has a Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. In February 2017, the FPSC approved expansion of the Cast Iron/Bare Steel clause to allow recovery of accelerated replacement of certain obsolete plastic pipe. The majority of cast iron and bare steel pipe has been removed from its system, with replacement of obsolete plastic pipe continuing until 2028 under the rider.

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NMGC

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.

NMGC's approved ROE for 2025 and 2024 was 9.375 per cent on an allowed equity capital structure of 52 per cent.

Base Rates:

On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates. On March 1, 2024, NMGC filed with the NMPRC a settlement with the support of all parties in the case for an increase of \$30 million USD in annual base revenues and maintaining NMGC's ROE at 9.375 per cent. The rates reflect the recovery of increased operating costs and capital investments in pipeline projects and related infrastructure, as well as a new customer information and billing system. NMGC also agreed to withdraw, and to not reassert in a future rate case application, its request for a regulatory asset for costs associated with its 2022 application for a certificate of public convenience and necessity for a liquefied natural gas storage facility in New Mexico. The NMPRC approved the rate case settlement on July 25, 2024. New rates became effective October 1, 2024.

Fuel Recovery:

NMGC recovers gas supply costs through a PGAC. This clause recovers actual costs for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, transmission, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC can adjust charges based on the next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. NMGC received approval of its PGAC Continuation in December 2024, for the four-year period ending December 2028.

Brunswick Pipeline

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

Other Electric Utilities

BLPC

BLPC is regulated by the Fair Trading Commission ("FTC"), under the Utilities Regulation (Procedural) Rules 2003. BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's approved regulated return on rate base was 10 per cent for 2025 and 2024.

Base Rates:

In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately \$1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities 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.

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License:

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.

Fuel Recovery:

BLPC's fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The calculation of the fuel charge is adjusted on a monthly basis and reported to the FTC for approval.

GBPC

GBPC is regulated by the GBPA. The GBPA has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. GBPC's approved regulated return on rate base is 8.52 per cent.

Electricity Act, 2024:

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, another Bahamian regulator, regulate GBPC.

Base Rates:

There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. On August 1, 2024, as required by the GBPA Operating Protocol and Regulatory Framework Agreement, GBPC filed a rate plan proposal.

Fuel Recovery:

GBPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner. In 2025 and 2024, the fuel pass through charge was adjusted monthly, in-line with actual fuel and other associated costs.

8. Investments Subject to Significant Influence and Equity Income

millions of dollars	Carrying Value As at December 31		Equity Income For the year ended December 31		Percentage of Ownership
	2025	2024	2025	2024	2025
NSPML	\$ 462	\$ 475	\$ 41	\$ 44	100.0
M&NP ⁽¹⁾	108	124	18	20	12.9
Lucelec ⁽¹⁾	55	55	5	4	19.5
WTI ⁽²⁾	9	—	—	—	50.0
Bear Swamp ⁽³⁾	—	—	(1)	2	50.0
LIL ⁽⁴⁾	—	—	—	29	—
	\$ 634	\$ 654	\$ 63	\$ 99	

- (1) Emera has significant influence over the operating and financial decisions of these companies through Board representation and therefore, records its investment in these entities using the equity method.
- (2) On March 5, 2025, NSPI, the Canada Infrastructure Bank ("CIB") and the Wskijinu'k Mtno'taquow Agency ("WMA") announced the Wasoqonatl transmission line project to create a reliable 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's ownership interest is based on a 50 per cent indirect voting interest in WTI. As of December 31, 2025, NSPI's economic interest based on the \$9 million invested is 26 per cent.
- (3) The investment balance in Bear Swamp is in a credit position primarily as a result of a \$179 million distribution received in 2015. Bear Swamp's credit investment balance of \$84 million (2024 - \$92 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.
- (4) On June 4, 2024, Emera completed the sale of its equity interest in the LIL. For further details, refer to note 4.

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Equity investment in Lucelec includes a \$10 million difference between the cost and the underlying FV of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 33). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of dollars	December 31 2025	December 31 2024
Balance Sheets		
Current assets	\$ 40	\$ 37
PP&E	1,380	1,425
Regulatory assets	782	778
Non-current assets	27	27
Total assets	\$ 2,229	\$ 2,267
Current liabilities	\$ 87	\$ 55
Long-term debt ⁽¹⁾	1,495	1,570
Non-current liabilities	185	167
Equity	462	475
Total liabilities and equity	\$ 2,229	\$ 2,267

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

9. Other Income, Net

For the millions of dollars	Year ended December 31	
	2025	2024
AFUDC	\$ 62	\$ 53
Interest income	37	23
Pension non-current service cost recovery	25	35
FX gains (losses)	25	(58)
Gain on sale of LIL, net of transaction costs ⁽¹⁾	4	182
Transaction costs related to the pending sale of NMGC ⁽¹⁾	(2)	(25)
Charges related to wind-down costs and certain asset impairments ⁽²⁾	—	(29)
Other	14	22
	\$ 165	\$ 203

(1) For more information related to the gain on sale, after transaction costs, of Emera's indirect minority interest in the LIL and the pending sale of NMGC, refer to note 4.

(2) Primarily related to the wind-down of Block Energy LLC.

10. Interest Expense, Net

For the millions of dollars	Year ended December 31	
	2025	2024
Interest on debt	\$ 1,048	\$ 1,004
Allowance for borrowed funds used during construction	(30)	(23)
Other	14	(8)
	\$ 1,032	\$ 973

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11. Income Taxes

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

millions of dollars	2025		2024	
Income before provision for income taxes	\$	1,171	\$	409
Income taxes, at statutory income tax rate		176 15%		61 15%
<i>Domestic reconciling items:</i>				
Investment tax credits		(36) (3)%		— —%
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		(18) (2)%		(44) (11)%
Valuation allowance		(14) (1)%		(30) (7)%
Net Part VI.1 tax		14 1%		14 3%
Interest and financing expenses		— —%		(30) (7)%
Additional impact from the sale of LIL equity interest		— —%		11 3%
Other		(8) (1)%		(3) (1)%
Provincial income taxes ⁽¹⁾		(31) (3)%		(130) (32)%
<i>Foreign reconciling items:</i>				
United States				
Federal tax rate variance		58 5%		32 8%
Production tax credits		(51) (4)%		(41) (10)%
State income tax, net of federal income tax benefit		49 4%		30 7%
Amortization of deferred income tax regulatory liabilities		(45) (4)%		(37) (9)%
Investment tax credits		(39) (3)%		(8) (2)%
Deferral and amortization of Investment tax credits		21 2%		(4) (1)%
Impairment charges		13 1%		35 9%
Other		(3) —%		(8) (2)%
Other foreign jurisdictions		(5) —%		(7) (2)%
Income tax expense (recovery)	\$	81 7%	\$	(159) (39)%

(1) The majority of provincial income taxes relate to Nova Scotia.

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.

Excessive Interest and Financing Expenses Limitation ("EIFEL") Regime:

On June 20, 2024, Bill C-59, an Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023, and certain provisions of the budget tabled in Parliament on March 28, 2023, was enacted. Bill C-59 includes the EIFEL regime, which is effective January 1, 2024. EIFEL applies to limit a company's net interest and financing expense deduction to no more than 30 per cent of earnings before interest, income taxes, depreciation, and amortization for tax purposes. Any denied interest and financing expenses under the EIFEL regime can be carried forward indefinitely.

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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 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 and therefore a \$54 million deferred income tax asset and related income tax benefit was recorded during Q4 2024. In addition, Emera recognized a \$4 million income tax benefit related to the reversal of a deferred income tax liability on the wind-up of the financing structure. During 2024, 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.

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

millions of dollars	2025	2024
Canada	\$ 157	\$ (175)
United States	961	534
Other	53	50
Income before provision for income taxes	\$ 1,171	\$ 409

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

millions of dollars	Canada (Federal)	Canada (Provincial)	United States	Other	Total
2025					
Current income taxes	\$ (6)	\$ —	\$ 16	\$ —	\$ 10
Deferred income taxes - exclusive of the components listed below	23	21	208	5	257
Benefits of operating loss carryforwards	(41)	(39)	(2)	(2)	(84)
Net tax credits	—	—	(72)	—	(72)
Adjustments to beginning of the year valuation allowance	(14)	(13)	(3)	—	(30)
Income tax expense (recovery)	\$ (38)	\$ (31)	\$ 147	\$ 3	\$ 81
2024					
Current income taxes	\$ 29	\$ —	\$ 4	\$ —	\$ 33
Deferred income taxes - exclusive of the components listed below	(104)	(98)	208	—	6
Benefits of operating loss carryforwards	(2)	(2)	(76)	—	(80)
Adjustments to beginning of the year valuation allowance	(31)	(30)	—	—	(61)
Net tax credits	—	—	(57)	—	(57)
Income tax (recovery) expense	\$ (108)	\$ (130)	\$ 79	\$ —	\$ (159)

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

millions of dollars	2025	2024
Deferred income tax assets:		
Tax loss carryforwards	\$ 1,028	\$ 1,118
Tax credit carryforwards	596	534
Regulatory liabilities	295	321
Pension and other post-retirement liabilities	173	197
Derivative instruments	143	144
Other	463	432
Total deferred income tax assets before valuation allowance	2,698	2,746
Valuation allowance	(317)	(322)
Total deferred income tax assets after valuation allowance	\$ 2,381	\$ 2,424
Deferred income tax liabilities:		
PP&E	\$ (3,462)	\$ (3,307)
Regulatory assets	(358)	(420)
Pension and other post-retirement assets	(335)	(286)
Other	(321)	(350)
Total deferred income tax liabilities	\$ (4,476)	\$ (4,363)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax assets	\$ 421	\$ 392
Long-term deferred income tax liabilities	(2,516)	(2,331)
Net deferred income tax liabilities	\$ (2,095)	\$ (1,939)

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for certain loss carryforwards, denied interest and financing expenses and unrealized capital losses on long-term debt and investments. A valuation allowance of \$317 million has been recorded as at December 31, 2025 (2024 - \$322 million) related to the loss carryforwards, denied interest and financing expenses, long-term debt and investments. During 2025, the Company recognized a \$28 million (2024 - \$58 million) net tax benefit primarily due to the utilization of certain loss carryforwards, which were subject to a valuation allowance at the beginning of the year.

The Company intends to indefinitely reinvest earnings from certain foreign operations. It is impractical to estimate the amount of income and withholding tax that might be payable if such earnings were repatriated.

Emera's net operating loss ("NOL"), capital loss and tax credit carryforwards and their expiration periods as at December 31, 2025 consisted of the following:

millions of dollars	Tax Carryforwards	Subject to Valuation Allowance	Net Tax Carryforwards	Expiration Period
Canada				
NOL	\$ 2,649	\$ (876)	\$ 1,773	2026 - 2045
Capital loss	55	(55)	—	Indefinite
Tax credit	2	(2)	—	2028 - 2044
United States				
Federal NOL	\$ 909	\$ (1)	\$ 908	2037 - Indefinite
State NOL	937	(30)	907	2026 - Indefinite
Capital loss	1	—	1	2029
Tax credit	595	(1)	594	2026 - 2045
Other				
NOL	\$ 108	\$ (20)	\$ 88	2026 - 2031

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

millions of dollars	2025	2024
Balance, January 1	\$ 42	\$ 37
Increases due to tax positions related to current year	6	6
Increases due to tax positions related to a prior year	1	2
Decreases due to tax positions related to a prior year	(3)	(3)
Balance, December 31	\$ 46	\$ 42

Unrecognized tax benefits relate to the timing of certain tax deductions at NSPI and research and development tax credits primarily at TEC. The total amount of unrecognized tax benefits as at December 31, 2025 was \$46 million (2024 - \$42 million), which would decrease the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was \$12 million (2024 - \$10 million) with \$2 million interest expense recognized in the Consolidated Statements of Income (2024 - \$1 million). No penalties have been accrued.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is \$126 million (2024 - \$126 million), including interest. NSPI has prepaid \$55 million (2024 - \$55 million) of the amount in dispute, as required by CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute of the 2006 through 2010 taxation years. Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the difference, if any, either owed to, or refunded from, the CRA. The related tax deductions will be available in subsequent years.

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

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

Emera files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, and St. Lucia income tax returns. As at December 31, 2025, the Company's tax years still open to examination by taxing authorities include 2006 and subsequent years.

12. Common Stock

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

Issued and outstanding:	2025		2024	
	millions of shares	millions of dollars	millions of shares	millions of dollars
Balance, December 31, 2024	295.94	\$ 9,042	284.12	\$ 8,462
Conversion of Convertible Debentures	0.02	1	—	—
Issuance of common stock under ATM program ⁽¹⁾⁽²⁾	0.19	9	5.12	261
Issued under the DRIP, net of discounts	4.83	293	6.10	291
Senior management stock options exercised and Employee Share Purchase Plan	0.78	42	0.60	28
Balance, December 31, 2025	301.76	\$ 9,387	295.94	\$ 9,042

(1) For the year ended December 31, 2024, a total of 5,117,273 common shares were issued under Emera's ATM program at an average price of \$51.52 per share for gross proceeds of \$264 million (\$261 million net of after-tax issuance costs).

(2) 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.

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As at December 31, 2025, the following common shares were reserved for issuance: 5 million (2024 - 6 million) under the senior management stock option plan, 1 million (2024 - 2 million) under the employee common share purchase plan and 20 million (2024 - 12 million) under the DRIP.

The issuance of common shares under the common share compensation arrangements does not allow the plans to exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2025, Emera was in compliance with this requirement.

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 US Securities and Exchange Commission (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.

13. Earnings Per Share

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

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

For the millions of dollars (except per share amounts)	Year ended December 31	
	2025	2024
Numerator		
Net income attributable to common shareholders	\$ 1,014.2	\$ 493.6
Diluted numerator	1,014.2	493.6
Denominator		
Weighted average shares of common stock outstanding - basic	299.2	289.1
Stock-based compensation	0.5	0.1
Weighted average shares of common stock outstanding - diluted	299.7	289.2
Earnings per common share		
Basic	\$ 3.39	\$ 1.71
Diluted	\$ 3.38	\$ 1.71

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14. Accumulated Other Comprehensive Income

The components of AOCI are as follows:

millions of dollars	Unrealized gain (loss) on translation of self-sustaining foreign operations	Net change in net investment hedges	Gains (losses) on derivatives recognized as cash flow hedges	Net change on available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the year ended December 31, 2025						
Balance, January 1, 2025	\$ 1,396	\$ (163)	\$ 12	\$ –	\$ 16	\$ 1,261
OCI before reclassifications	(623)	82	–	2	–	(539)
Amounts reclassified from AOCI	–	–	(2)	–	153	151
Net current period OCI	(623)	82	(2)	2	153	(388)
Balance, December 31, 2025	\$ 773	\$ (81)	\$ 10	\$ 2	\$ 169	\$ 873
For the year ended December 31, 2024						
Balance, January 1, 2024	\$ 369	\$ (24)	\$ 14	\$ (2)	\$ (52)	\$ 305
OCI before reclassifications	1,027	(139)	–	2	–	890
Amounts reclassified from AOCI	–	–	(2)	–	68	66
Net current period OCI	1,027	(139)	(2)	2	68	956
Balance, December 31, 2024	\$ 1,396	\$ (163)	\$ 12	\$ –	\$ 16	\$ 1,261

The reclassifications out of AOCI are as follows:

For the millions of dollars		Year ended December 31	
		2025	2024
Affected line item in the Consolidated Financial Statements			
Gains on derivatives recognized as cash flow hedges			
Interest rate hedge	Interest expense, net	\$ (2)	\$ (2)
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial (gains) losses	Other income, net	\$ (2)	\$ 2
Past service costs (gains)	Other income, net	2	(2)
Amounts reclassified into obligations	Pension and post-retirement benefits	156	68
Total before tax		156	68
Income tax expense		(3)	—
Total net of tax		\$ 153	\$ 68
Total reclassifications out of AOCI, net of tax, for the period		\$ 151	\$ 66

15. Inventory

As at millions of dollars	December 31 2025	December 31 2024
Materials	\$ 484	\$ 453
Fuel	337	328
Total	\$ 821	\$ 781

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16. Derivative Instruments

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

As at millions of dollars	Derivative Assets		Derivative Liabilities	
	December 31 2025	December 31 2024	December 31 2025	December 31 2024
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	\$ 22	\$ 25	\$ 33	\$ 44
FX forwards	3	27	2	3
	25	52	35	47
<i>HFT derivatives:</i>				
Power swaps and physical contracts	51	34	50	30
Natural gas swaps, futures, forwards, physical contracts	238	236	695	660
	289	270	745	690
<i>Other derivatives:</i>				
Equity derivatives	8	—	—	2
FX forwards	8	—	1	34
	16	—	1	36
Total gross current derivatives	330	322	781	773
<i>Impact of master netting agreements:</i>				
Regulatory deferral	(1)	(7)	(1)	(7)
HFT derivatives	(131)	(148)	(131)	(148)
Total impact of master netting agreements	(132)	(155)	(132)	(155)
Less: Derivatives classified as held for sale ⁽¹⁾	—	(1)	—	(1)
Total derivatives	\$ 198	\$ 166	\$ 649	\$ 617
Current ⁽²⁾	156	115	534	526
Long-term ⁽²⁾	42	51	115	91
Total derivatives	\$ 198	\$ 166	\$ 649	\$ 617

(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 note 4.

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

Cash Flow Hedges

On May 26, 2021, a treasury lock was settled for a gain of \$19 million that is being amortized through interest expense over 10 years as the underlying hedged item settles. 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 (2024 - \$2 million) were reclassified from AOCI into interest expense, net. The Company expects \$2 million of unrealized gains currently in AOCI to be reclassified into net income within the next twelve months.

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Regulatory Deferral

The Company has recorded the following changes with respect to derivatives receiving regulatory deferral:

millions of dollars	Commodity swaps and forwards	FX forwards	Commodity swaps and forwards	FX forwards
For the year ended December 31	2025		2024	
Unrealized (loss) gain in regulatory assets	\$ (36)	\$ 1	\$ (27)	\$ 5
Unrealized gain (loss) in regulatory liabilities	13	(12)	11	33
Realized gain in regulatory assets	(7)	—	(8)	—
Realized loss in regulatory liabilities	5	—	4	—
Realized loss (gain) in inventory ⁽¹⁾	15	(8)	11	(8)
Realized loss (gain) in regulated fuel for generation and purchased power ⁽²⁾	18	(4)	50	(6)
Total change in derivative instruments	\$ 8	\$ (23)	\$ 41	\$ 24

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period and hedging relationships that have been terminated or the hedged transaction is no longer probable.

As at December 31, 2025, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2026	2027-2028
<i>Commodity swaps and forwards purchases:</i>		
Natural gas (MMBtu)	7	10
Power (MWh)	1	—
<i>FX forwards:</i>		
FX contracts (millions of USD)	\$ 175	\$ 72
Weighted average rate	1.3569	1.3534
% of USD requirements	64%	16%

HFT Derivatives

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

For the millions of dollars	Year ended December 31	
	2025	2024
Power swaps and physical contracts in non-regulated operating revenues	\$ 4	\$ 12
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	463	195
Total gains in net income	\$ 467	\$ 207

As at December 31, 2025, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2026	2027	2028	2029	2030 and thereafter
Natural gas purchases (Mmbtu)	473	140	57	28	47
Natural gas sales (Mmbtu)	492	99	18	6	3
Power purchases (MWh)	1	—	—	—	—
Power sales (MWh)	2	1	—	—	—

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Other Derivatives

As at December 31, 2025, the Company had equity derivatives in place to manage cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and FX forwards in place to manage cash flow risk associated with forecasted USD cash inflows. The equity derivatives hedge the return on 3.2 million shares and extends until December of 2026. The FX forwards have a combined notional amount of \$300 million USD and expire in 2026 through 2028.

For the millions of dollars	Year ended December 31			
	2025		2024	
	FX Forwards	Equity Derivatives	FX Forwards	Equity Derivatives
Unrealized gain (loss) in OM&G	\$ –	\$ 8	\$ –	\$ (2)
Unrealized gain (loss) in other income, net	39	–	(44)	–
Realized gain in OM&G	–	33	–	16
Realized loss in other income, net	(16)	–	(12)	–
Total gains (losses) in net income	\$ 23	\$ 41	\$ (56)	\$ 14

Credit Risk

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

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

As at December 31, 2025, the maximum exposure the Company had to credit risk was \$2 billion (2024 - \$1.3 billion), which included accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, FX and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The total cash deposits/collateral on hand as at December 31, 2025 was \$301 million (2024 - \$303 million), which mitigated the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

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

As at December 31, 2025, the Company had \$207 million (2024 - \$140 million) in financial assets, considered to be past due, which have been outstanding for an average 77 days. The FV of these financial assets was \$192 million (2024 - \$128 million), the difference of which was included in the allowance for credit losses. These assets primarily relate to accounts receivable from electric and gas revenue.

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Concentration Risk

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

As at	December 31, 2025		December 31, 2024	
	millions of dollars	% of total exposure	millions of dollars	% of total exposure
Receivables, net				
<i>Regulated utilities:</i>				
Residential	\$ 471	20%	\$ 376	22%
Commercial	211	9%	184	11%
Industrial	94	4%	73	4%
Other	177	8%	105	6%
Cash collateral	3	0%	46	3%
	956	41%	784	46%
<i>Trading group:</i>				
Credit rating of A- or above	146	6%	88	5%
Credit rating of BBB- to BBB+	78	3%	42	2%
Not rated	416	18%	165	10%
	640	27%	295	17%
Other accounts receivable	408	17%	331	20%
Classification as assets held for sale ⁽¹⁾	134	6%	118	7%
	2,138	92%	1,528	90%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	96	4%	91	5%
Credit rating of BBB- to BBB+	3	0%	1	0%
Not rated	99	4%	74	5%
	198	8%	166	10%
	\$ 2,336	100%	\$ 1,694	100%

(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 note 4.

Cash Collateral

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

As at millions of dollars	December 31 2025	December 31 2024
Cash collateral provided to others	\$ 193	\$ 198
Cash collateral received from others	\$ 5	\$ 5

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

As at December 31, 2025, the total FV of derivatives in a liability position was \$649 million (December 31, 2024 - \$617 million). If the credit ratings of the Company were reduced below investment grade, the full value of the net liability position could be required to be posted as collateral for these derivatives.

17. FV Measurements

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

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

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

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

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

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

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

As at millions of dollars	December 31, 2025			
	Level 1	Level 2	Level 3	Total
Assets				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	\$ 21	\$ —	\$ —	\$ 21
FX forwards	—	3	—	3
	21	3	—	24
<i>HFT derivatives:</i>				
Power swaps and physical contracts	(1)	29	7	35
Natural gas swaps, futures, forwards, physical contracts and related transportation	1	88	34	123
	—	117	41	158
<i>Other derivatives:</i>				
FX forwards	—	8	—	8
Equity derivatives	8	—	—	8
	8	8	—	16
Total assets	29	128	41	198
Liabilities				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	\$ 11	\$ 21	\$ —	\$ 32
FX forwards	—	2	—	2
	11	23	—	34
<i>HFT derivatives:</i>				
Power swaps and physical contracts	(4)	31	7	34
Natural gas swaps, futures, forwards and physical contracts	1	115	464	580
	(3)	146	471	614
<i>Other derivatives:</i>				
FX forwards	—	1	—	1
	—	1	—	1
Total liabilities	8	170	471	649
Net assets (liabilities)	\$ 21	\$ (42)	\$ (430)	\$ (451)

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As at millions of dollars	December 31, 2024			
	Level 1	Level 2	Level 3	Total
Assets				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	\$ 15	\$ 3	\$ —	\$ 18
FX forwards	—	27	—	27
	15	30	—	45
<i>HFT derivatives:</i>				
Power swaps and physical contracts	2	23	5	30
Natural gas swaps, futures, forwards, physical contracts and related transportation	13	52	27	92
	15	75	32	122
Less: Derivatives classified as held for sale ⁽¹⁾	—	(1)	—	(1)
Total assets	30	104	32	166
Liabilities				
<i>Regulatory deferral:</i>				
Commodity swaps and forwards	18	19	—	37
FX forwards	—	3	—	3
	18	22	—	40
<i>HFT derivatives:</i>				
Power swaps and physical contracts	2	21	4	27
Natural gas swaps, futures, forwards and physical contracts	(11)	89	437	515
	(9)	110	441	542
<i>Other derivatives:</i>				
FX forwards	—	34	—	34
Equity derivatives	2	—	—	2
	2	34	—	36
Less: Derivatives classified as held for sale ⁽¹⁾	—	(1)	—	(1)
Total liabilities	11	165	441	617
Net assets (liabilities)	\$ 19	\$ (61)	\$ (409)	\$ (451)

(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 note 4.

The change in the FV of the Level 3 financial assets and liabilities for the year ended December 31, 2025 was as follows:

millions of dollars	HFT Derivatives		
	Power	Natural gas	Total
Assets			
Balance, beginning of period	\$ 5	\$ 27	\$ 32
Total realized and unrealized gains (losses) included in non-regulated operating revenues	2	7	9
Balance, December 31, 2025	\$ 7	\$ 34	\$ 41
Liabilities			
Balance, beginning of period	\$ 4	\$ 437	\$ 441
Total realized and unrealized gains (losses) included in non-regulated operating revenues	3	27	30
Balance, December 31, 2025	\$ 7	\$ 464	\$ 471

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

The Company uses a modelled pricing valuation technique for determining the FV of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the FV measurements categorized within Level 3 of the FV hierarchy:

millions of dollars	FV		Significant Unobservable Input	Low	High	Weighted average ⁽¹⁾
	Assets	Liabilities				
As at December 31, 2025						
HFT derivatives - Power swaps and physical contracts	\$ 7	\$ 7	Third-party pricing	\$27.35	\$150.55	\$88.79
HFT derivatives - Natural gas swaps, futures, forwards and physical contracts	34	464	Third-party pricing	\$0.51	\$18.45	\$11.85
Total	\$ 41	\$ 471				
Net liability		\$ 430				
As at December 31, 2024						
HFT derivatives - Power swaps and physical contracts	5	4	Third-party pricing	\$25.60	\$139.65	\$82.63
HFT derivatives - Natural gas swaps, futures, forwards and physical contracts	27	437	Third-party pricing	\$2.20	\$17.54	\$8.57
Total	\$ 32	\$ 441				
Net liability		\$ 409				

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

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

As at millions of dollars	Carrying Amount	FV	Level 1	Level 2	Level 3	Total
December 31, 2025	\$ 19,654	\$ 18,956	\$ —	\$ 18,535	\$ 421	\$ 18,956
December 31, 2024	\$ 18,407	\$ 17,941	\$ —	\$ 17,688	\$ 253	\$ 17,941

The Company has designated \$1.2 billion USD denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations. The Company's Hybrid Notes are contingently convertible into preferred shares in the event of bankruptcy or other related events. A redemption option on or after June 15, 2026 is available and at the control of the Company. The Hybrid Notes are classified as Level 2 financial assets. As at December 31, 2025, the FV of the Hybrid Notes was \$1.2 billion USD (2024 - \$1.2 billion USD). An after-tax foreign currency gain of \$82 million was recorded in AOCI for the year ended December 31, 2025 (2024 - \$139 million after-tax loss).

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18. Related Party Transactions

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

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling \$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.
- 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.

19. Receivables and Other Current Assets

As at millions of dollars	December 31 2025	December 31 2024
Customer accounts receivable - billed	\$ 1,265	\$ 834
Customer accounts receivable - unbilled	400	342
Capitalized transportation capacity ⁽¹⁾	238	216
Cash collateral provided to others	193	198
Prepaid expenses	105	105
Sales tax receivable	84	21
Income tax receivable	19	22
Allowance for credit losses	(15)	(12)
Other	150	85
Total receivables and other current assets	\$ 2,439	\$ 1,811

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

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20. Leases

Lessee

The Company has operating leases for buildings, land, telecommunication services, and rail cars and finance leases for land and buildings. Emera's leases have remaining lease terms of 2 years to 61 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain they will be exercised.

As at millions of dollars	Classification	December 31 2025	December 31 2024
<i>Operating leases:</i>			
Right-of-use asset	Other long-term assets	\$ 48	\$ 52
<i>Operating lease liabilities:</i>			
Current	Other current liabilities	1	3
Long-term	Other long-term liabilities	53	54
Total operating lease liabilities		\$ 54	\$ 57
<i>Finance leases:</i>			
Right-of-use asset	PP&E	\$ 66	\$ 21
<i>Finance lease liabilities:</i>			
Current	Other current liabilities	3	—
Long-term	Other long-term liabilities	66	21
Total finance lease liabilities		\$ 69	\$ 21

The amounts recognized in the Consolidated Statements of Income consisted of the following:

As at millions of dollars	Classification	Year ended December	
		2025	2024
<i>Operating leases:</i>			
Operating Lease expense	OM&G	\$ 15	\$ 11
<i>Finance leases:</i>			
Variable costs for power generation finance leases	Regulated fuel for generation and purchased power	\$ 115	\$ 112
Amortization of right-of-use asset	Depreciation and amortization	4	—
Interest on finance lease liability	Interest expense, net	3	—
Total finance lease liabilities		\$ 122	\$ 112

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

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
<i>Operating leases:</i>							
Minimum lease payments	\$ 3	\$ 3	\$ 3	\$ 3	\$ 3	\$ 109	\$ 124
Less imputed interest							(70)
Total future minimum lease payments for operating leases							\$ 54
<i>Finance Leases:</i>							
Minimum lease payments	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4	\$ 161	\$ 181
Less imputed interest							(112)
Total future minimum lease payments for finance leases							\$ 69

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

For the millions of dollars (except as indicated)	Year ended December 31 2025		Year ended December 31 2024	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows for leases	\$ 10	\$ 3	\$ 10	\$ 1
Right-of-use assets obtained in exchange for lease obligations	\$ –	\$ –	\$ –	\$ –
Operating leases	\$ 22	\$ –	\$ –	\$ –
Finance leases	\$ –	\$ 49	\$ –	\$ 16
Weighted average remaining lease term (years)	44	33	44	31
Weighted average discount rate	3.98%	5.54%	3.96%	5.20%

Lessor

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

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

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

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

The total net investment in direct finance and sales-type leases consist of the following:

As at millions of dollars	December 31 2025	December 31 2024
Total minimum lease payment to be received	\$ 1,180	\$ 1,310
Less: amounts representing estimated executory costs	(166)	(182)
Minimum lease payments receivable	\$ 1,014	\$ 1,128
Estimated residual value of leased property (unguaranteed)	183	183
Less: Credit loss reserve	(1)	(2)
Less: unearned finance lease income	(580)	(655)
Net investment in direct finance and sales-type leases	\$ 616	\$ 654
Principal due within one year (included in "Receivables and other current assets")	44	44
Net Investment in direct finance and sales type leases - long-term	\$ 572	\$ 610

As at December 31, 2025, future minimum lease payments to be received for each of the next five years and in aggregate thereafter were as follows:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Minimum lease payments to be received	\$ 97	\$ 96	\$ 96	\$ 95	\$ 94	\$ 702	\$ 1,180
Less: executory costs							(166)
Total							\$ 1,014

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21. Property, Plant and Equipment

PP&E consisted of the following regulated and non-regulated assets:

As at millions of dollars	Estimated useful life	December 31 2025 ⁽¹⁾	December 31 2024 ⁽¹⁾
Generation	10 to 131	\$ 14,673	\$ 14,297
Transmission	5 to 80	3,379	3,106
Distribution	5 to 65	9,359	8,512
Gas transmission and distribution	20 to 75	4,815	4,658
General plant and other ⁽²⁾	2 to 60	3,643	3,078
Total cost		35,869	33,651
Less: Accumulated depreciation ⁽²⁾		(10,845)	(10,442)
		25,024	23,209
Construction work in progress ⁽²⁾		2,384	2,959
Net book value		\$ 27,408	\$ 26,168

(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 and excluded from the table above. For further details on the pending transaction, refer to note 4.

(2) SeaCoast owns a 50% undivided ownership interest in a jointly owned 26-mile pipeline lateral located in Florida, which went into service in 2020. At December 31, 2025, SeaCoast's share of plant in service was \$27 million USD (2024 - \$27 million USD), and accumulated depreciation of \$3 million USD (2024 - \$3 million USD). SeaCoast's undivided ownership interest is financed with its funds and all operations are accounted for as if such participating interest were a wholly owned facility. SeaCoast's share of direct expenses of the jointly owned pipeline is included in "OM&G" in the Consolidated Statements of Income.

22. Employee Benefit Plans

Emera maintains a number of contributory defined-benefit ("DB") and defined-contribution ("DC") pension plans, which cover substantially all of its employees. The Company also provides non-pension benefits for its retirees.

Emera's net periodic benefit cost included the following:

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Benefit Obligation and Plan Assets

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

For the millions of dollars	Year ended December 31			
	2025		2024	
	DB pension plans	Non-pension benefit plans	DB pension plans	Non-pension benefit plans
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO"):				
Balance, January 1	\$ 2,367	\$ 241	\$ 2,273	\$ 227
Service cost	35	3	35	3
Plan participant contributions	5	5	6	5
Interest cost	114	12	110	12
Plan amendments	—	5	—	—
Benefits paid	(160)	(22)	(153)	(21)
Actuarial losses (gains) ⁽¹⁾	(18)	(2)	13	(3)
FX translation adjustment	(49)	(10)	83	18
Balance, December 31	\$ 2,294	\$ 232	\$ 2,367	\$ 241
Change in plan assets:				
Balance, January 1	\$ 2,493	\$ 54	\$ 2,298	\$ 48
Employer contributions	38	15	36	13
Plan participant contributions	5	5	6	5
Benefits paid	(160)	(22)	(153)	(21)
Actual return on assets, net of expenses	345	5	226	4
FX translation adjustment	(46)	(2)	80	5
Balance, December 31	\$ 2,675	\$ 55	\$ 2,493	\$ 54
Funded status, end of year	\$ 381	\$ (177)	\$ 126	\$ (187)

(1) The actuarial gains recognized in the period are primarily due to higher than expected investment returns and changes in actuarial assumptions.

Plans with PBO/APBO in Excess of Plan Assets

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

millions of dollars	2025			
	DB pension plans	Non-pension benefit plans	DB pension plans	Non-pension benefit plans
PBO/APBO	\$ 96	\$ 212	\$ 95	\$ 219
FV of plan assets	13	—	11	—
Funded status	\$ (83)	\$ (212)	\$ (84)	\$ (219)

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

The ABO for the DB pension plans was \$2,114 million as at December 31, 2025 (2024 - \$2,255 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 were as follows:

millions of dollars	2025		2024	
	DB pension plans		DB pension plans	
ABO	\$ 92		\$ 90	
FV of plan assets	13		11	
Funded status	\$ (79)		\$ (79)	

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Balance Sheet

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

As at millions of dollars	December 31 2025		December 31 2024	
	DB pension plans	Non-pension benefit plans	DB pension plans	Non-pension benefit plans
Other current liabilities	\$ (5)	\$ (17)	\$ (5)	\$ (21)
Liabilities associated with assets held for sale ⁽¹⁾	(1)	(4)	—	(1)
Long-term liabilities	(77)	(191)	(78)	(196)
Other long-term assets	473	—	208	—
Assets held for sale ⁽¹⁾	(9)	46	1	31
AOCI, net of tax and regulatory assets	125	7	354	22
Deferred income tax expense in AOCI	(12)	—	(8)	(1)
Net amount recognized	\$ 494	\$ (159)	\$ 472	\$ (166)

(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 note 4.

Amounts Recognized in AOCI and Regulatory Assets

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

millions of dollars	Regulatory assets	Actuarial (gains) losses	Past service gains
DB Pension Plans:			
Balance, January 1, 2025	\$ 363	\$ (17)	\$ —
Amortized in current period	(9)	1	—
Current year changes	(51)	(158)	—
Change in FX rate	(16)	—	—
Balance, December 31, 2025	\$ 287	\$ (174)	\$ —
Non-pension benefits plans:			
Balance, January 1, 2025	\$ 29	\$ (8)	\$ —
Amortized in current period	—	1	(3)
Current year changes	(3)	2	1
Change in FX rate	(1)	—	—
Balance, December 31, 2025	\$ 25	\$ (5)	\$ (2)

As at millions of dollars	December 31 2025		December 31 2024	
	DB pension plans	Non-pension benefit plans	DB pension plans	Non-pension benefit plans
Actuarial (gains) losses	\$ (174)	\$ (5)	\$ (17)	\$ (8)
Past service gains	—	(2)	—	—
Deferred income tax expense	12	—	8	1
AOCI, net of tax	(162)	(7)	(9)	(7)
Regulatory assets	287	14	363	29
Assets held for sale ⁽¹⁾	—	11	—	—
AOCI, net of tax and regulatory assets	\$ 125	\$ 18	\$ 354	\$ 22

(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 note 4.

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Benefit Cost Components

Emera's net periodic benefit cost included the following:

As at millions of dollars	Year ended December 31			
	2025		2024	
	DB pension plans	Non-pension benefit plans	DB pension plans	Non-pension benefit plans
Service cost	\$ 35	\$ 3	\$ 35	\$ 3
Interest cost	114	12	110	12
Expected return on plan assets	(164)	(2)	(160)	(2)
Current year amortization of:				
Actuarial losses (gains)	(1)	(1)	3	(2)
Past service gains	–	3	–	(2)
Regulatory assets	9	–	9	(2)
Settlement, curtailments	–	–	–	1
Total	\$ (7)	\$ 15	\$ (3)	\$ 8

The expected return on plan assets is determined based on the market-related value of plan assets of \$2,686 million as at January 1, 2025 (2024 - \$2,571 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a multi-year period.

Pension Plan Asset Allocations

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

Asset Class	Target Range at Market		
Canadian Pension Plans:			
Short-term securities	0%	to	10%
Fixed income	34%	to	49%
Equities:			
Canadian	5%	to	15%
Non-Canadian	37%	to	61%
Non-Canadian Pension Plans:			
Cash and cash equivalents	0%	to	10%
Fixed income	29%	to	49%
Equities	48%	to	68%

Pension plan assets are overseen by the respective management pension committees in the sponsoring companies. All pension investments are in accordance with policies approved by the respective Board of Directors of each sponsoring company.

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The following tables set out the classification of the methodology used by the Company to FV its investments (for more information on the FV hierarchy and measurement, refer to note 17):

millions of dollars	NAV		Level 1	Level 2	Total	Percentage
As at			December 31, 2025			
Cash and cash equivalents	\$	–	\$ 76	\$ –	\$ 76	3%
Net in-transits		–	(27)	–	(27)	(1)%
<i>Equity securities:</i>						
Canadian		–	117	–	117	4%
United States		–	262	–	262	10%
Other		–	146	–	146	5%
<i>Fixed income securities:</i>						
Government		–	–	110	110	4%
Corporate		–	–	68	68	3%
Other		–	–	13	13	–%
Mutual funds		–	5	–	5	–%
Open-ended investments measured at NAV ⁽¹⁾		1,335	–	–	1,335	50%
Common collective trusts measured at NAV ⁽²⁾		570	–	–	570	22%
Total	\$	1,905	\$ 579	\$ 191	\$ 2,675	100%

As at	December 31, 2024					
Cash and cash equivalents	\$	–	\$ 39	\$ –	\$ 39	2%
Net in-transits		–	(27)	–	(27)	(1)%
<i>Equity securities:</i>						
Canadian		–	109	–	109	4%
United States		–	312	–	312	12%
Other		–	140	–	140	5%
<i>Fixed income securities:</i>						
Government		–	–	132	132	5%
Corporate		–	–	92	92	4%
Other		–	–	22	22	1%
Mutual funds		–	13	–	13	1%
Open-ended investments measured at NAV ⁽¹⁾		1,142	–	–	1,142	46%
Common collective trusts measured at NAV ⁽²⁾		519	–	–	519	21%
Total	\$	1,661	\$ 586	\$ 246	\$ 2,493	100%

- (1) Net asset value ("NAV") investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated at least monthly and the funds honour subscription and redemption activity regularly.
- (2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The funds honour subscription and redemption activity regularly.

Non-Pension Benefit Plans

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

Investments in Emera

As at December 31, 2025 and 2024, assets related to the pension funds and post-retirement benefit plans did not hold any material investments in Emera or its subsidiaries securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

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Cash Flows

The following table shows expected cash flows for DB pension and other post-retirement benefit plans:

millions of dollars	DB pension plans	Non-pension benefit plans
Expected employer contributions		
2026	\$ 34	\$ 17
Expected benefit payments		
2026	170	19
2027	174	19
2028	174	20
2029	176	20
2030	173	20
2031 - 2035	899	109

Assumptions

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

(weighted average assumptions)	2025		2024	
	DB pension plans	Non-pension benefit plans	DB pension plans	Non-pension benefit plans
Benefit obligation - December 31:				
Discount rate - past service	5.11%	4.87%	5.07%	4.91%
Discount rate - future service	5.21%	5.08%	5.12%	5.00%
Rate of compensation increase	3.73%	3.82%	3.73%	3.72%
Health care trend - initial (next year)	—	6.73%	—	6.53%
- ultimate	—	3.77%	—	3.77%
- year ultimate reached		2045		2044
Benefit cost for year ended December 31:				
Discount rate - past service	5.07%	4.91%	4.89%	4.89%
Discount rate - future service	5.12%	5.00%	4.88%	4.89%
Expected long-term return on plan assets	6.42%	3.65%	6.43%	3.69%
Rate of compensation increase	3.73%	3.72%	3.87%	3.85%
Health care trend - initial (current year)	—	6.53%	—	6.04%
- ultimate	—	3.77%	—	3.76%
- year ultimate reached		2044		2043

Actual assumptions used differ by plan.

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

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

DC Pension Plan

Emera also provides a DC pension plan for certain employees. The Company's contribution for the year ended December 31, 2025 was \$53 million (2024 - \$51 million).

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23. Goodwill

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

millions of dollars	2025	2024
Balance, January 1	\$ 5,858	\$ 5,871
Change in FX rate	(278)	504
Impairment charges	—	(214)
Classified as assets held for sale ⁽¹⁾	—	(303)
Balance, December 31	\$ 5,580	\$ 5,858

(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 note 4.

Goodwill is subject to an annual assessment for impairment at the reporting unit level. The goodwill on Emera's Consolidated Balance Sheets at December 31, 2025, related to the TEC and PGS reporting units.

In Q4 2025, qualitative assessments were 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.

In Q3 2024, Emera announced 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, pre-tax, in Q3 2024. The reduced NMGC goodwill balance is included in the NMGC disposal unit classified as held for sale. For further details, refer to note 4.

24. Short-Term Debt

Emera's short-term borrowings consist of commercial paper issuances, advances on revolving and non-revolving credit facilities and short-term notes. Short-term debt and the related weighted-average interest rates as at December 31 consisted of the following:

millions of dollars	2025	Weighted average interest rate	2024	Weighted average interest rate
Florida Electric Utility				
Advances on revolving credit facilities	\$ 1,059	4.01%	\$ 915	4.77%
Canadian Electric Utilities				
Advances on non-revolving credit facilities	500	3.35%	—	—%
Bank indebtedness	42	—%	—	—%
Gas Utilities and Infrastructure				
PGS - Advances on revolving credit facilities	199	4.63%	199	5.36%
NMGC - Advances on revolving credit facilities	20	4.77%	46	5.52%
NMGC - Advances on non-revolving term facilities	96	4.63%	—	—%
Other Electric Utilities				
GBPC - Advances on revolving credit facilities	—	—%	19	7.20%
Other				
TECO Finance - Advances on revolving credit and term facilities	7	5.21%	265	5.53%
Emera - Bank indebtedness	—	—%	2	—%
	\$ 1,923		\$ 1,446	
Adjustment				
Classification as liabilities held for sale ⁽¹⁾	(116)		(46)	
Short-term debt	\$ 1,807		\$ 1,400	

(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 note 4.

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

millions of dollars	Maturity	2025	2024
TEC - committed revolving credit facility	2030	\$ 1,645	\$ 1,151
TECO Finance - committed revolving credit facility	2030	548	576
NSPI - non-revolving credit facility	2026	500	—
PGS - revolving credit facility	2030	343	360
NMGC - revolving credit facility ⁽¹⁾	2027	171	180
NMGC - non-revolving term facility ⁽¹⁾	2026	96	—
Other - committed revolving credit facilities	Various	29	35
Total		3,332	2,302
Less:			
Advances under revolving credit and term facilities		1,881	1,400
Letters of credit issued within the credit facilities		3	4
Total advances under available facilities		1,884	1,404
Available capacity under existing agreements		\$ 1,448	\$ 898

(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 note 4.

The weighted average interest rate on outstanding short-term debt at December 31, 2025 was 4.24 per cent (2024 - 5.05 per cent).

Recent Significant Financing Activity by Segment

Florida Electric Utilities

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.

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.

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.

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 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.

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25. Other Current Liabilities

As at millions of dollars	December 31 2025	December 31 2024
Accrued charges	\$ 229	\$ 189
Accrued interest on long-term debt	137	106
Pension and post-retirement liabilities (note 22)	22	26
Sales and other taxes payable	16	11
Income tax payable	3	4
Other	128	153
	\$ 535	\$ 489

26. Long-Term Debt

Bonds, notes and debentures are at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

Long-term debt as at December 31 consisted of the following:

millions of dollars	Weighted average interest rate ⁽¹⁾		Maturity	2025	2024
	2025	2024			
Florida Electric Utility					
Senior unsecured notes	4.46%	4.36%	2029 - 2051	\$ 6,271	\$ 5,720
Canadian Electric Utilities					
NSPI - Commercial paper ⁽²⁾	Variable	Variable	2029	\$ 559	\$ 177
NSPI - Senior unsecured notes	4.98%	5.12%	2026 - 2097	3,114	3,184
				\$ 3,673	\$ 3,361
Gas Utilities and Infrastructure					
PGS - Senior unsecured notes	5.63%	5.63%	2028 - 2053	\$ 1,268	\$ 1,331
NMGC - Senior unsecured notes	3.78%	3.78%	2026 - 2051	665	698
EBP - Secured loan notes	Variable	Variable	2028	219	250
				\$ 2,152	\$ 2,279
Other Electric Utilities					
Unsecured loan notes	4.08%	4.06%	2026 - 2032	\$ 142	\$ 143
Unsecured loan notes	Variable	Variable	2027 - 2028	113	104
Secured senior notes and debentures ⁽³⁾	2.19%	2.38%	2026 - 2040	171	169
				\$ 426	\$ 416
Other					
Unsecured loan notes	Variable	Variable	2026 - 2029	\$ 723	\$ 992
Senior unsecured notes	3.99%	3.99%	2026 - 2046	3,358	3,525
Senior unsecured notes	4.84%	4.84%	2030	500	500
Fixed to floating subordinated notes ⁽⁴⁾	6.75%	6.75%	2076	1,645	1,727
Junior subordinated notes	6.80%	7.63%	2054 - 2056	1,713	720
				\$ 7,939	\$ 7,464
Adjustments					
Debt issuance costs				\$ (144)	\$ (137)
Classification as liabilities held for sale ⁽⁵⁾				(663)	(696)
Amount due within one year ⁽⁶⁾				(1,201)	(234)
				\$ (2,008)	\$ (1,067)
Long-Term Debt				\$ 18,453	\$ 18,173

(1) Weighted average interest rate of fixed rate long-term debt.

(2) Discount notes are backed by a revolving credit facility which matures in 2029.

(3) Notes are issued and payable in either USD or BBD.

(4) In 2025, the Company recognized \$113 million in interest expense (2024 - \$110 million) related to its fixed to floating subordinated notes.

(5) On August 5, 2024, Emera announced an agreement to sell NMGC. Since Q3 2024, NMGC's liabilities were classified as held for sale. For further details on the pending transaction, refer to note 4.

(6) Excludes NMGC amounts which are classified as current liabilities associated with assets held for sale.

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

millions of dollars	Maturity	2025	2024
Emera - committed revolving credit facility ⁽¹⁾	June 2029	\$ 1,300	\$ 1,300
NSPI - revolving credit facility ⁽¹⁾	June 2029	800	800
Emera - Unsecured non-revolving credit facility	February 2027	200	200
Total		\$ 2,300	\$ 2,300
Less:			
Borrowings under credit facilities		1,284	1,169
Letters of credit issued inside credit facilities		17	12
Use of available facilities		\$ 1,301	\$ 1,181
Available capacity under existing agreements		\$ 999	\$ 1,119

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to \$50 million.

Debt Covenants

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements. Emera's significant covenants are listed below:

	Financial Covenant	Requirement	As at December 31, 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 by Segment

Florida Electric Utility

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.

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 September 25, 2025, EUSHI Finance, 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 US Securities and Exchange Commission ("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.

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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.

Long-Term Debt Maturities

As at December 31, 2025, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Florida Electric Utility	\$ —	\$ —	\$ —	\$ 685	\$ —	\$ 5,586	\$ 6,271
Canadian Electric Utilities	40	—	—	599	—	3,034	3,673
Gas Utilities and Infrastructure ⁽¹⁾	127	31	637	—	—	1,357	2,152
Other Electric Utilities	102	90	126	18	54	36	426
Other	1,028	200	—	522	500	5,689	7,939
Total	\$ 1,297	\$ 321	\$ 763	\$ 1,824	\$ 554	\$ 15,702	\$ 20,461

(1) Includes NMGC maturities classified as held for sale.

27. Asset Retirement Obligations

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

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

millions of dollars	2025	2024
Balance, January 1	\$ 217	\$ 192
Accretion included in depreciation expense	11	10
Additions	5	11
Revisions in estimated cash flows	—	2
Classified as assets held for sale ⁽¹⁾	(1)	(1)
Liabilities settled	(2)	(2)
Change in FX rate	(2)	5
Balance, December 31	\$ 228	\$ 217

(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 note 4.

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28. Commitments and Contingencies

A. Commitments

As at December 31, 2025, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt and asset retirement obligations) for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2026	2027	2028	2029	2030	Thereafter	Total
Purchased power ⁽¹⁾	\$ 413	\$ 422	\$ 411	\$ 459	\$ 451	\$ 5,941	\$ 8,097
Transportation ^{(2) (3)}	780	588	478	413	370	2,954	5,583
Fuel, gas supply and storage ⁽⁴⁾	674	239	159	156	38	59	1,325
Capital projects	288	68	32	6	1	—	395
Other	144	69	53	49	42	294	651
	\$ 2,299	\$ 1,386	\$ 1,133	\$ 1,083	\$ 902	\$ 9,248	\$ 16,051

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 note 4.

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

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

(3) 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.

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

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.

B. Legal Proceedings

Superfund and Former Manufactured Gas Plant Sites

Previously, TEC had been a potentially responsible party ("PRP") for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, Peoples Gas System, Inc. is also now a PRP for those sites (in addition to third party PRPs for certain sites). While the aggregate joint and several liability associated with these sites has not changed as a result of the PGS legal separation, the sites continue to present the potential for significant response costs. As at December 31, 2025, the aggregate financial liability of the Florida utilities is estimated to be \$15 million (\$11 million USD), primarily at PGS. This estimate assumes that other involved PRPs are credit-worthy entities. This amount has been accrued and is primarily reflected in the long-term liability section under "Other long-term liabilities" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

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

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

Other Legal Proceedings

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

C. Principal Financial Risks and Uncertainties

Emera believes the following principal financial risks could 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"). Risks associated with derivative instruments and FV measurements are discussed in note 16 and note 17.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee ("ERMC") and monitored by the Board of Directors, to ensure risks are appropriately identified, assessed, monitored and subject to appropriate controls. The Board of Directors has a Safety and Risk Committee ("SRC") to assist in carrying out its 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.

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.

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.

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

Liquidity and Capital 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.

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 embargoes.

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.

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.

D. Guarantees and Letters of Credit

Emera has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit 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.

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.

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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.

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.

Collaborative Arrangements

For the years ended December 31, 2025 and 2024, the Company has identified the following material collaborative arrangements:

Through NSPI, the Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI's portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI's portion of operating expenses is recorded in "OM&G" on the Consolidated Statements of Income. In 2025, NSPI recognized \$12 million net expense (2024 - \$12 million) in "Regulated fuel for generation and purchased power" and \$3 million (2024 - \$3 million) in "OM&G" on the Consolidated Statements of Income.

29. Cumulative Preferred Stock

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

	Annual Dividend Per Share	Redemption Price per share	December 31, 2025		December 31, 2024	
			Issued and Outstanding	Net Proceeds	Issued and Outstanding	Net Proceeds
Series A	\$ 1.2378	\$ 25.00	6,000,000	\$ 147	4,866,814	\$ 119
Series B	Floating	\$ 25.00	—	\$ —	1,133,186	\$ 28
Series C	\$ 1.6085	\$ 25.00	10,000,000	\$ 245	10,000,000	\$ 245
Series E	\$ 1.1250	\$ 25.00	5,000,000	\$ 122	5,000,000	\$ 122
Series F	\$ 1.4372	\$ 25.00	8,000,000	\$ 195	8,000,000	\$ 195
Series H	\$ 1.5810	\$ 25.00	12,000,000	\$ 295	12,000,000	\$ 295
Series J	\$ 1.0625	\$ 25.00	8,000,000	\$ 196	8,000,000	\$ 196
Series L	\$ 1.1500	\$ 26.00	9,000,000	\$ 222	9,000,000	\$ 222
Total			58,000,000	\$ 1,422	58,000,000	\$ 1,422

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Characteristics of the First Preferred Shares:

First Preferred Shares ⁽¹⁾⁽²⁾	Annual Dividend Rate (%)	Current Annual Dividend (\$)	Minimum Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value (\$)	Right to Convert on a one for one basis
Fixed rate reset ⁽³⁾⁽⁴⁾						
Series A ⁽⁵⁾⁽⁶⁾	4.951	1.2378	1.84	August 15, 2030	25.00	Series B
Series C	6.434	1.6085	2.65	August 15, 2028	25.00	Series D
Series F ⁽⁷⁾	5.749	1.4372	2.63	February 15, 2030	25.00	Series G
Minimum rate reset ⁽³⁾⁽⁴⁾						
Series H	6.324	1.5810	4.90	August 15, 2028	25.00	Series I
Series J	4.250	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate						
Series E	4.500	1.1250			25.00	
Series L ⁽⁸⁾	4.600	1.1500		November 15, 2026	26.00	

- (1) Holders are entitled to receive fixed or floating cumulative cash dividends when declared by the Board of Directors of the Company.
- (2) On or after the specified redemption dates, the Company has the option to redeem for cash the outstanding First Preferred Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.
- (3) On the redemption and/or conversion option date the reset annual dividend per share will be determined by multiplying \$25.00 per share by the annual fixed or floating dividend rate, which for Series A, C, F and H is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield (Series H annual reset rate must be a minimum of 4.90 per cent).
- (4) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preferred Shares of a specified series. The Company has the right to redeem the outstanding Preferred Shares, Series B, D, G and I shares without the consent of the holder every five years thereafter for cash, in whole or in part at a price of \$25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption and \$25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date after August 15, 2028, February 15, 2025 and August 15, 2028, respectively. The reset dividend yield for Series I equals the Government of Treasury Bill Rate on the applicable reset date, plus 2.54 per cent.
- (5) On July 9, 2025, Emera announced that it would not redeem the outstanding Preferred Shares, Series A or B shares on August 15, 2025. During the conversion period between July 16, 2025 and July 31, 2025, subject to certain conditions, 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, by the end of the conversion period, the Company had determined that there would be outstanding less than 1 million Series B Shares on August 15, 2025. 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 August 15, 2025.
- (6) On July 16, 2025, Emera announced that the annual fixed dividend per share for Series A shares would reset from \$0.5456 to \$1.2378 for the five-year period from and including August 14, 2025.
- (7) On January 16, 2025, Emera announced that the annual fixed dividend per share for Series F shares would reset from \$1.0505 to \$1.4372 for the five-year period from and including February 15, 2025.
- (8) First Preferred Shares, Series L are redeemable at \$26.00 on or after November 15, 2026 to November 15, 2027, decreasing \$0.25 each year until November 15, 2030 and \$25.00 per share thereafter.

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

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

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

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30. Non-Controlling Interest in Subsidiaries

As at millions of dollars	December 31 2025	December 31 2024
Preferred shares of GBPC	\$ 14	\$ 14

Preferred shares of GBPC

Authorized:

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

Issued and outstanding:	2025		2024	
	number of shares	millions of dollars	number of shares	millions of dollars
Outstanding as at December 31	10,000	\$ 14	10,000	\$ 14

GBPC Non-Voting Cumulative Variable Perpetual Preferred Stock

The preferred shares are redeemable by GBPC after June 17, 2021, at \$1,000 Bahamian per share plus accrued and unpaid dividends and are entitled to a 6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually.

The Preferred Shares rank behind GBPC's current and future secured and unsecured debt and ahead of all of GBPC's current and future common stock.

31. Supplementary Information to Consolidated Statements of Cash Flows

For the millions of dollars	Year ended December 31	
	2025	2024
Changes in non-cash working capital:		
Inventory	\$ (63)	\$ 38
Receivables and other current assets	(703)	(154)
Accounts payable	(40)	536
Other current liabilities	49	32
Total non-cash working capital	\$ (757)	\$ 452

For the millions of dollars	Year ended December 31	
	2025	2024
Supplemental disclosure of cash paid:		
Interest	\$ 1,003	\$ 989
Income taxes		
Canada - Federal	\$ 32	\$ 27
United States	9	7
Total Income taxes paid	\$ 41	\$ 34
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	\$ 292	\$ 291
Accrued proceeds from disposal of investment subject to significant influence	\$ 4	\$ 25
Decrease in accrued capital expenditures	\$ (54)	\$ —
Supplemental disclosure of operating activities:		
Net change in short-term regulatory assets and liabilities	\$ 277	\$ (118)

32. Stock-Based Compensation

ECSP and Common Shareholders DRIP

Eligible employees can participate in the ECSP. As of December 31, 2025, the plan allows employees to make cash contributions of a minimum of \$25 per month to a maximum of \$20,000 CAD or \$15,000 USD per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employees' contributions to the plan.

The plan allows reinvestment of dividends for all participants except for where prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares. As at December 31, 2025, Emera was in compliance with this requirement.

Compensation cost for shares issued under the ECSP for the year ended December 31, 2025 was \$3 million (2024 - \$4 million) and was included in "OM&G" on the Consolidated Statements of Income.

The Company also has a Common Shareholders DRIP, which provides an opportunity for shareholders residing in Canada to reinvest dividends and purchase common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera's common shares for common shares purchased with the reinvestment of cash dividends. The discount was 2 per cent in 2025.

Stock-Based Compensation Plans

Stock Option Plan:

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of 10 years. The exercise price of the stock options is the closing price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded before the date on which the option is granted. The maximum aggregate number of shares issuable under this plan is 14.7 million shares. As at December 31, 2025, Emera was in compliance with this requirement.

Stock options vest in 20 per cent increments on the first, second, third, fourth and fifth anniversaries of the date of the grant. If an option is not exercised within 10 years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of common stocks to be optioned to any optionee shall not exceed five per cent of the issued and outstanding common stocks on the date the option is granted.

In accordance with the Stock Option Plan, vested options may be exercised during the full term of the option following the option holders date of retirement, six months following a termination without just cause or death, and within sixty days following the date of termination for just cause or resignation. If stock options are not exercised within such time, they expire.

The Company uses the Black-Scholes valuation model to estimate the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis.

The following table shows the weighted average FV per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

	2025	2024
Weighted average FV per option	\$ 6.12	\$ 4.66
Expected term ⁽¹⁾	5 years	5 years
Risk-free interest rate ⁽²⁾	2.71%	3.56%
Expected dividend yield ⁽³⁾	5.06%	6.11%
Expected volatility ⁽⁴⁾	20.90%	20.67%

(1) The expected term of the option awards is calculated based on historical exercise behaviour and represents the period of time that the options are expected to be outstanding.

(2) Based on the Bank of Canada five-year government bond yields.

(3) Incorporates current dividend rates and historical dividend increase patterns.

(4) Estimated using the five-year historical volatility.

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The following table summarizes stock option information for 2025:

	Total Options		Non-Vested Options ⁽¹⁾	
	Number of Options	Weighted average exercise price per share	Number of Options	Weighted average grant date fair-value
Outstanding as at December 31, 2024	3,796,040	\$ 50.53	1,607,490	\$ 5.08
Granted	678,000	57.00	678,000	6.25
Exercised	(357,559)	45.57	N/A	N/A
Forfeited	N/A	N/A	N/A	N/A
Vested	N/A	N/A	(496,710)	4.80
Options outstanding December 31, 2025	4,116,481	\$ 52.03	1,788,780	\$ 5.60
Options exercisable December 31, 2025 ⁽²⁾⁽³⁾	2,327,701	\$ 51.13		

(1) As at December 31, 2025, there was \$8 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 3 years (2024 - \$6 million, 3 years).

(2) As at December 31, 2025, the weighted average remaining term of vested options was 5 years with an aggregate intrinsic value of \$38 million (2024 - 4 years, \$11 million).

(3) As at December 31, 2025, the FV of options that vested in the year was \$2 million (2024 - \$2 million).

Compensation cost recognized for stock options for the year ended December 31, 2025 was \$3 million (2024 - \$2 million), which was included in "OM&G" on the Consolidated Statements of Income.

As at December 31, 2025, cash received from option exercises was \$16 million (2024 - \$3 million). The total intrinsic value of options exercised for the year ended December 31, 2025 was \$6 million (2024 - \$1 million). The range of exercise prices for the options outstanding as at December 31, 2025 was \$39.93 to \$60.03 (2024 - \$39.93 to \$60.03).

Share Unit Plans:

The Company has DSU, PSU and RSU plans. The plans and the liabilities are marked-to-market at the end of each period based on the closing common share price of the last trading day before the end of the period.

Deferred Share Unit Plans:

Under the Directors' DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors' fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the Board, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by Emera's closing common share price on the date DSUs are redeemed.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50 per cent of the value of their actual annual incentive award (25 per cent in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When short-term incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Unless otherwise determined by the Management Resources and Compensation Committee ("MRCC"), following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the ten trading days prior to a given calculation date. Payments are made in cash.

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In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2025 is presented in the following table:

	Employee DSU	Weighted Average Grant Date FV	Director DSU	Weighted Average Grant Date FV
Outstanding as at December 31, 2024	789,088	\$ 42.65	828,856	\$ 47.12
Granted including DRIP	87,985	50.46	120,684	52.04
Exercised	(138,189)	33.16	(188,438)	42.18
Outstanding and exercisable as at December 31, 2025	738,884	\$ 45.36	761,102	\$ 49.12

Compensation cost recognized for employee and director DSU's for the year ended December 31, 2025 was \$29 million (2024 - \$13 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2025 were \$9 million (2024 - \$4 million tax expense). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2025 for employees was \$50 million (2024 - \$43 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2025 for directors was \$51 million (2024 - \$45 million). Cash payments made during the year ended December 31, 2025 associated with the DSU plan were \$20 million (2024 - \$2 million).

Performance Share Unit Plan:

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

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee PSUs for the year ended December 31, 2025 is presented in the following table:

	Employee PSU	Weighted Average Grant Date FV	Aggregate intrinsic value
Outstanding as at December 31, 2024	832,093	\$ 52.57	\$ 50
Granted including DRIP	332,562	52.61	
Exercised	(120,434)	59.77	
Forfeited	(134,283)	58.40	
Outstanding as at December 31, 2025	909,938	\$ 50.77	\$ 68

Compensation cost recognized for the PSU plan for the year ended December 31, 2025 was \$31 million (2024 - \$18 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2025 were \$8 million (2024 - \$5 million). Cash payments made during the year ended December 31, 2025 associated with the PSU plan were \$7 million (2024 - \$14 million).

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Restricted Share Unit Plan:

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

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee RSUs for the year ended December 31, 2025 is presented in the following table:

	Employee RSU	Weighted Average Grant Date FV	Aggregate intrinsic value
Outstanding as at December 31, 2024	653,148	\$ 52.36	\$ 41
Granted including DRIP	270,800	52.62	
Exercised	(171,274)	59.77	
Forfeited	(24,463)	50.79	
Outstanding as at December 31, 2025	728,211	\$ 50.77	\$ 57

Compensation cost recognized for the RSU plan for the year ended December 31, 2025 was \$23 million (2024 - \$15 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2025 were \$6 million (2024 - \$4 million). Cash payments made during the year ended December 31, 2025 associated with the RSU plan were \$11 million (2024 - \$10 million).

33. Variable Interest Entities

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

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

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

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

As at	December 31, 2025		December 31, 2024	
	Total assets	Maximum exposure to loss	Total assets	Maximum exposure to loss
millions of dollars				
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	\$ 462	\$ 6	\$ 475	\$ 6

34. Subsequent Events

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 23, 2026, the date the financial statements were issued.

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As of March 31, 2026

Emera Leadership

Scott C. Balfour

President and
Chief Executive Officer,
Emera Inc.

Mike Barrett

Executive Vice President,
Legal and General Counsel,
Emera Inc.

Archie Collins

President and Chief Executive Officer,
Tampa Electric

Jared Green

Chief Financial Officer, Emera Inc.

Peter Gregg

Executive Vice President, Strategy and
Policy, Emera Inc.

Karen Hutt

Executive Vice President, Corporate
Development, Emera Inc.

Janelle Poole

Vice President, Corporate Affairs,
Emera Inc.

Michael Roberts

Chief Human Resources Officer,
Emera Inc.

Ryan Shell

President,
New Mexico Gas Company Inc.

Vivek Sood

President and Chief Executive Officer,
Nova Scotia Power

Judy Steele

President and Chief Operating Officer,
Emera Energy

Helen Wesley

President, Peoples Gas System, Inc.

Board of Directors

Karen H. Sheriff

Chair of the Board
Picton, Ontario

Scott C. Balfour

President and Chief Executive Officer
Halifax, Nova Scotia

James V. Bertram

Calgary, Alberta

Isabelle Courville

Mont-Tremblant, Quebec

Henry E. Demone

Lunenburg, Nova Scotia

Paula Y. Gold-Williams

San Antonio, Texas

Kent M. Harvey

New York, New York

B. Lynn Loewen

Montreal, Quebec

Brian J. Porter

Toronto, Ontario

Ian E. Robertson

Oakville, Ontario

Jochen E. Tilk

Toronto, Ontario

Carla M. Tully

Arlington, Virginia

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For general inquiries, please contact
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Information regarding Company
news and initiatives, including our 2025
Annual Report, is available
on our website: www.emera.com

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TSX Trust Company
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Halifax, Nova Scotia B3J 3B7
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F: 1.888.249.6189
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Transfer Agent - United States

Equiniti Trust Company, LLC
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This Annual Report contains forward-looking
information. Actual future results may
differ materially. Additional financial and
operational information is filed electronically
with various securities commissions in
Canada, copies of which are available
electronically under Emera's profile
on SEDAR+ at www.sedarplus.ca and on
EDGAR at www.sec.gov.

Share Listings

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)
Common shares: EMA
Preferred shares: EMA.PR.A,
EMA.PR.C, EMA.PR.E,
EMA.PR.F, EMA.PR.H,
EMA.PR.J and EMA.PR.L
Barbados Stock Exchange (BSE)
Depository receipts: EMABDR
Bahamas International Securities
Exchange (BISX)
Depository receipts: EMAB

Shares Outstanding

Common shares: 301,754,258
(as of December 31, 2025)

Dividends Paid in 2025

Emera Inc. paid common share dividends
of \$0.725 per quarter in Q1, Q2 and Q3
(annualized rate of \$2.90 per common share)
and \$0.7325 in Q4 (annualized rate of \$2.93
per common share), for an effective annual
common share dividend rate of \$2.9075 per
common share.

Dividend Payments in 2026

Subject to approval by the Board of Directors,
dividends for Emera Inc. are payable on or
about the 15th of February, May, August
and November. A first quarter common
share dividend of \$0.7325, a Series A First
Preferred Share dividend of \$0.3094, a
Series C First Preferred Share dividend
of \$0.40213, a Series E First Preferred
Share dividend of \$0.28125, a Series F First
Preferred Share dividend of \$0.35931, a
Series H First Preferred Share dividend of
\$0.39525, a Series J First Preferred Share
dividend of \$0.265625, a Series L First
Preferred Share dividend of \$0.28750 were
declared on January 13, 2026 and paid on
February 13, 2026.

Dividend Reinvestment and Share Purchase Plan

Emera's Dividend Reinvestment and Share
Purchase Plan is available to shareholders
who reside in Canada. The plan provides
a convenient and economical means of
acquiring additional common shares
through the reinvestment of dividends with
a discount of up to five per cent. In 2025, the
discount was two per cent. Plan participants
may also contribute cash payments of up
to \$5,000 per quarter. Plan participants
pay no commissions, service charges or
brokerage fees for shares purchased under
the plan. Please contact Investor Services
if you have questions or wish to receive an
enrollment form.

Direct Deposit Service

Registered shareholders may have dividends
deposited directly to any bank account in
Canada. To arrange this service, please
contact TSX Trust Company. Beneficial
shareholders should contact their financial
intermediary.

Quarterly Earnings

Quarterly earnings are expected to be
announced in May, August and November
2026. Year-end results for 2026 will be
released in February 2027.



Emera is represented in the TSX Composite,
TSX Capped Utilities, TSX60 and select
world indexes.



Changes to Chart of Accounts for Nova Scotia Power Inc. (Consolidated)
These reflect the changes from the submission on December 31, 2024 to December 31, 2025

The following Account numbers were added in 2025:

Account Number	Account Description
175700	WASOQONATL TRANSMISSION
210200	SHORT TERM NOTES
211250	AP LTSA
213300	AP COMMON SHARE DEDUCTION
213350	AP PARKING PAYROLL DEDUCTION
213360	AP TRANSIT PASS PAYROLL DEDUCTION
242810	ACCRUED INC TAX NON CANADIAN RESIDENCE
412140	REG RES TIME OF USE FAM AA FUEL COST
412150	REG RES TIME OF USE FAM BA FUEL COST
412210	REG RES TIME OF USE DSM BA COST
412315	REG RES CPP DSM BA COST
412540	REG SMALL GEN TIME OF USE FAM AA FUEL COST
412610	REG SMALL GEN TIME OF USE DSM BA COST
412715	REG SMALL GEN CPP DSM BA COST
413190	REG RES DSM BA COST
413280	REG RES ACCRUED DSM BA COST
413415	REG RES TIME OF DAY DSM BA COST
413580	REG RES TIME OF DAY ACCRUED DSM BA COST
414190	REG SMALL GEN DSM BA COST
414280	REG SMALL GEN ACCRUED DSM BA COST
414390	REG GEN DSM BA COST
414480	REG GEN ACCRUED DSM BA COST
414580	REG LARGE GENERAL DSM BA COST
414640	REG GENERAL TIME OF USE FAM AA FUEL COST
414710	REG GENERAL TIME OF USE DSM BA COST
414900	REG GENERAL CPP DSM BA COST
415190	REG SMALL IND DSM BA COST
415280	REG SMALL IND ACCRUED DSM BA COST
415390	REG MEDIUM IND DSM BA COST
415480	REG MEDIUM IND ACCRUED DSM BA COST
415580	REG LARGE IND DSM BA COST
415690	REG LARGE IND INTERRUPT RIDER DSM BA COST
415855	REG SHORE POWER DSM BA COST
415970	REG GRLF REPLACEMENT LOAD FOLLOWING DSM BA COST
415990	REG TIME OF USE REAL TIME PRICE DSM BA COST
416190	REG UNMETERED DSM BA COST

416280	REG UNMETERED ACCRUED DSM BA COST
416315	REG MUNICIPAL DSM BA COST
534100	COST RECOVERY EXECUTIVE STOCK OPTION PLAN

The following Lines of Business was added in 2025:

Line of Business Number	Line of Business Description
131	EV Charging

There were no new Locations added in 2025.

The following Cost Centre numbers were added in 2025:

Cost Centre Number	Cost Centre Description
041	OFFICE OF THE CFO
059	PAYROLL
122	OFFICE OF THE CDO
130	COMMERCIAL INVESTMENTS AND FINANCIAL ANALYSIS
151	BUSINESS TRANSFORMATION
160	DIVERSITY, EQUITY AND INCLUSION
161	BUSINESS VALUE TEAM
163	ERP PRODUCT SUPPORT

There were no new Intercompany numbers added in 2025.

Chart of Accounts for Nova Scotia Power Inc. (Consolidated)
As of December 31, 2025

INTRODUCTION

The Oracle account number consists of a twenty-nine digit "**Accounting Flexfield**". The flexfield is made up of eight segments as shown below.

CO	Account	Line of Bus	Location	CC	Inter-Company	Future Use	Future Use
XXX	XXXXXX	XXX	XXXX	XXX	XXX	XXXX	XXX

A complete listing of all Segments is provided in **Appendix A**.

The first segment is titled **Company** and is a three digit number identifying Nova Scotia Power as company 001 and Nova Scotia Power Energy Marketing Inc. as company 100.

The second segment is titled **Account Number** and is a six digit number which indicates the type of item involved. Expense types include accounts with values between 500000 and 699999.

The third segment is titled **Line of Business** and is a three digit number used to record a set of highly related functions that serve a set of transactions or business need.

The fourth segment is titled **Location** and is a four digit number used to record the related physical or geographic location.

The fifth segment is titled **Cost Centre** and is a three digit number used to differentiate function groups.

The sixth segment is titled **Inter-Company** and is a three digit number indicating the corresponding legal entity. This segment will contain zeros if the transaction is not between legal entities.

The final two segments are titled **Future Use** and these segments currently default to zero because they are not being used. These segments have been added to allow for expansion of the Chart of Accounts, as required.

APPENDIX A

Chart of Accounts - All Segments and Their Descriptors in the COA Structure

ACCOUNT SEGMENT

Account Segment Value	Account Segment Description
111050	PETTY CASH FUNDS
111600	CASH SCOTIABANK
111650	CASH ROYAL BANK IMPREST ACCOUNT
111700	CASH BNS US FUNDS
111800	CASH CIBC
111850	CASH ROYAL BANK
111900	CASH CIBC US BANK
115250	AR TRADE
115300	AR MISC PAYMENTS CLEARING
115350	AR ACCRUED INTEREST
115400	AR ST WATER HEATER LOANS
115450	AR MARKETING SALES
115500	AR MARKETING SALES ETS UNITS
115650	AR UNBILLED REV LARGE CUSTOMER
115700	AR UNBILLED REV OTHER ELECTRIC
115750	AR UNBILLED REVENUE
115800	AR POSTED MARGIN
115850	AR CSM DSM
115900	AR CSM DSM EFFICIENCY NS
115950	AR CSM DSM ENSL FINANCING
116050	AR COMMODITY DERIVATIVE
116150	AR ARM CLEARING
116900	ALLOWANCE FOR DOUBTFUL ACCOUNTS
117050	AR PST REBATE
117100	AR EMPLOYEE ADVANCES OTHER
117150	AR ARBITRATION CONTRACT
117200	AR PUITTA TAX REBATE
117250	AR RETURNS TO SUPPLIERS
117300	AR HST
117350	AR OTHER NON TRADE
117600	AR FEDERAL EXCISE TAX RECIEVABLE
118150	INTERCOMPANY AR TRADE
119100	INCOME TAX RECEIVABLE
121050	INVENTORY MATERIALS
121060	INVENTORY MATERIALS ADJ
121200	INVENTORY INTER ORG TRANSFER

121300	INVENTORY OBSOLESCENCE
121700	INVENTORY ASH
122050	INVENTORY COAL
122100	INVENTORY COAL FX
122150	INVENTORY BIOMASS
122200	INVENTORY BUNKER
122250	INVENTORY BUNKER C FX
122350	INVENTORY PROPANE
122400	INVENTORY DIESEL
122450	INVENTORY LIGHT OIL
122500	INVENTORY ADDITIVES
122550	INVENTORY MERCURY SORBENT
122600	INVENTORY MERCURY SORBENT FX
122650	INVENTORY FUEL
124050	INVENTORY EMISSION COMPLIANCE
128050	ST DERIV ASSET HFT
128400	ST DERIV ASSET HFT TREASURY
130050	ST REG ASSETS OTHER
130060	ST REG ASSET HYDRO GENERATION FACILITIES
130100	ST REG ASSET UNAMORT DEFEAS ISSUE COSTS
130200	ST REG ASSET DEF OF DSM
130250	ST REG ASSET DEFERRAL OF FAM
130300	ST REG ASSET DERIV INSTRUMENTS
130310	ST REG ASSET DERIV INSTR TREASURY
130600	ST REG ASSET DERIV INSTRUMENT FX
130700	ST REG ASSET STORM RIDER
130800	ST REG ASSET STORM RESTORATION COSTS
130810	ST REG ASSET UNRECOVERED NET BOOK VALUE
130820	ST REG ASSET ACCUM RESERVE COST OF REMOVAL
140100	DUE FROM RELATED PARTY
141050	PREPAID GRANTS
141100	PREPAID INSURANCE
141150	PREPAID OTHER
141350	PREPAID TRAVEL
141400	PREPAID OCCUPANCY TAXES
142100	ST OTHER NON REGULATORY ASSETS
162600	PPE REGULATED
162610	PPE REGULATED ADJ
162650	CONTRIBUTED CAPITAL REGULATED
163600	ACCUM DEP PPE REGULATED
163610	ACCUM DEP PPE REGULATED ADJ
163700	ACCUM DEP CONTRIBUTED CAPITAL REG
163800	CWIP REGULATED

163810	CWIP REGULATED ADJ
163850	CWIP CLEARING
163900	RWIP REGULATED
163910	RWIP REGULATED ADJ
170100	LT INCOME TAX RECEIVABLE
171050	LT DIT ASSET LIABILITY FAM
172050	LT DERIV ASSET HFT
172350	LT DERIV ASSET HFT TREASURY
173050	DEFERRED PENSION RETIREE BENEFIT
175700	WASOQONATL TRANSMISSION
180050	LT REG ASSET UNAMORT DEFEASANCE COSTS
180450	LT REG ASSET RENEWABLE TO RETAIL
180500	LT REG ASSET DIT REGULATORY
180600	LT REG ASSET DEFERRAL OF DSM
180700	LT REG ASSET DEFERRAL OF FAM
180750	LT REG ASSET OTHER
180760	LT REG ASSET HYDRO GENERATION FACILITIES
180800	LT REG ASSET DERIV INSTRUMENTS
180810	LT REG ASSET DERIV INSTR TREASURY
180850	LT REG ASSET FCR DEFERRAL
181550	LT REG ASSET UARB TAX DEFERRAL
181700	LT REG ASSET STORM RIDER
181800	LT REG ASSET STORM RESTORATION COSTS
181810	LT REG ASSET UNRECOVERED NET BOOK VALUE
191150	LT WATER HEATER LOANS RECEIVABLE
191200	LT RECEIVABLE MARKETING SALES
191350	LT OTHER NON REG ASSETS
191600	LT INTERCOMPANY INVESTMENTS
191850	LT RIGHT OF USE ASSETS - OPERATING LEASE
194050	LT UNAMORTIZED DISCOUNTS
194150	LT DEFERRED HEDGING PREMIUMS FX
194200	LT OTHER ISSUE COSTS
194250	LT DEFERRED INV PREMIUM
194350	LT DEFERRED FINANCING COSTS
197050	INTANGIBLES
197100	INTANGIBLES ACCUM AMORTIZATION
197150	INTANGIBLES CWIP REGULATED
210150	BANK INDEBTEDNESS
210200	SHORT TERM NOTES
210350	DEBT DUE WITHIN ONE YEAR
211150	AP TRADE
211160	AP TRADE ADJ
211250	AP LTSA
211300	AP PROCUREMENT CARDS

211350	AP AUTOMATED ACCRUAL
211360	AP AUTOMATED ACCRUAL ADJ
211400	AP ACCRUED COMMODITY DERIVATIVE
211410	AP ACCRUED CONVERSION GOODS RECEIPT
211450	AP ACCRUED FUEL
211500	AP ACCRUED FUEL FX
211550	AP ACCRUED LIABILITIES
211850	AP INVENTORY ACCRUAL
211950	AP POSTED MARGIN
212050	AP HOLDBACKS
212100	AP HEALTH DENTAL
212150	AP LIFE ADD
212250	AP DC PENSION
212300	AP DB PENSION
212350	AP CHARITY DONATIONS EMPLOYEES
212355	AP CHARITY DONATIONS EMPLOYEES IWK
212400	AP SOCIAL CLUB DUES
212500	AP UNION DUES LIVING AWAY ALLOW
212550	AP UNION DUES TECHNICAL TRAINING
212600	AP UNION DUES TRAINING COSTS
212650	AP UNION DUES RELOCATION ALLOW
212700	AP LONG TERM DISABILITY
212750	AP GOOD NEIGHBOUR ENERGY FUND
212800	AP CIS REFUND CLEARING
212850	AP CONSUMER DEPOSITS
212900	AP ACCRUE INT ON CONSUMER DEPOSIT
212950	AP WATER RENTALS PAYABLE
213150	AP RRSP
213300	AP COMMON SHARE DEDUCTION
213350	AP PARKING PAYROLL DEDUCTION
213360	AP TRANSIT PASS PAYROLL DEDUCTION
213900	AP PURCHASE PRICE VARIANCE
214100	AP PAYROLL FEDERAL INCOME TAX
214750	AP OTHER
217050	INTERCOMPANY AP TRADE
222105	INCOME TAX PAYABLE
221150	WITHHOLDING TAX PAYABLE
222050	ST ACCRUED PENSION AND NON PENSION BENEFIT LIABILITY – NSP
223100	ST DERIV LIAB HFT
223300	ST DERIV LIAB HFT TREASURY
230050	ST REG LIAB OTHER
230100	ST REG LIAB DEFERRAL OF FAM
230150	ST REG LIAB DERIV INSTRUMENTS
230250	ST REG LIAB ACCUM RESERVE COST OF REMOVAL

230350	ST REG LIAB DERIV INSTRUMENT FX
230400	ST REG LIAB DERIV INSTR TREASURY
241050	ACCRUED INTEREST PAYABLE CDN
241200	ACCRUED INTEREST LT DEBT
242050	ACCRUED LIABILITIES
242100	ACCRUED LIABILITIES NON TRADE
242110	ACCRUED LIABILITIES TREASURY
242150	ACCRUED ST RSU DSU
242350	ACCRUED PAYROLL
242400	ACCRUED PAYROLL CLEARING
242450	ACCRUED INCENTIVE
242500	ACCRUED VACATION
242550	ACCRUED LABOUR OPERATIONS
242600	ACCRUED CPP EMPLOYEE
242650	ACCRUED WCB
242700	ACCRUED PARKING
242750	ACCRUED EI EMPLOYEE
242800	ACCRUED INCOME TAX PAYROLL
242810	ACCRUED INC TAX NON CANADIAN RESIDENCE
242850	ACCRUED PENSION DEFINED BENEFIT
242900	ACCRUED TFSA CONTRIBUTIONS
242950	ACCRUED RRSP CONTRIBUTIONS EES
243100	ACCRUED CREDIT UNION DEDUCTIONS EES
243150	ACCRUED UNION DUES EMPLOYEES
243200	ACCRUED COMMON SHARE PURCHASE PLAN EES
243250	ACCRUED DIRECTORS SHARE PURCHASE PROG
243350	ACCRUED OTHER PAYROLL DEDUCTIONS
243400	ACCRUED OVERTIME BANKED
243450	ACCRUED PENSION PLAN NSPI
243500	ACCRUED UNIDENTIFIED CASH
243750	ACCRUED IWK LOTTO
243800	ACCRUED OTHER LIABILITIES
243850	ACCRUED ST DSM LIABILITY
247400	ST UNEARNED REVENUE LIAB
247500	ST REGULATORY EMISSION COMPLIANCE
247560	CARBON TAX PAYABLE
247600	GST HST PAYABLE
247750	ST OTHER LIABILITIES
247760	ST LEASE LIABILITY - OPERATING LEASE
261050	UNAMORTIZED ISSUE COSTS
261100	CAPITAL LEASE OBLIGATION
261150	NSPI DEBENTURES
261250	LONG TERM DEBT

262050	LT DEF INCOME TAX LIABILITY
262100	LT DEF INC TAX LIABILITY FAM
263050	LT DERIV LIABILITY HFT
263250	LT DERIV LIABILITY HFT TREASURY
270100	LT REG LIAB RATE STABILIZATION DEF
270150	LT REG LIAB STREETLIGHTS
270200	LT REG LIAB MTM
270300	LT REG LIAB DEFERRAL OF FAM
270350	LT REG LIAB DERIVATIVE LIABILITY
270360	LT REG LIAB DERIVATIVE TREASURY
270400	LT REG LIAB DERIV LIABILITY FX
270600	LT REG LIAB ACCUM RESERVE COST OF REMOVAL
280050	SITE RESTORATION RESERVE
280100	SITE RESTORATION RESERVE ACCRETION
280200	ASSET RETIREMENT OBLIGATION
281050	LT ACCRUED PENSION LIAB NSPI
283270	LT REGULATORY EMISSION COMPLIANCE
283300	LT UNEARNED REVENUE LIAB
283450	LONG TERM ACCRUED INTEREST
283500	LT DSU RSU
283900	LT LIABILITIES OTHER
283950	LT DSM LIABILITY
283960	LT LEASE LIABILITY - OPERATING LEASE
331100	COMMON SHARES INTERCOMPANY
334050	AOCI PENSION
337250	COMMON DIVIDENDS INTERCOMPANY
338050	OPENING RE
338150	OPENING RE CURRENT YEAR ADJ
412110	REG RES TIME OF USE NON FUEL DEMAND BASE
412120	REG RES TIME OF USE NON FUEL ENERGY ALLHOURS
412130	REG RES TIME OF USE FAM BASE FUEL
412140	REG RES TIME OF USE FAM AA FUEL COST
412150	REG RES TIME OF USE FAM BA FUEL COST
412160	REG RES TIME OF USE NON FUEL ENERGY PEAK
412170	REG RES TIME OF USE NON FUEL ENERGY OFF PEAK
412180	REG RES TIME OF USE DSM COST RECOVERY RIDER
412210	REG RES TIME OF USE DSM BA COST
412310	REG RES CPP NON FUEL DEMAND BASE
412315	REG RES CPP DSM BA COST
412320	REG RES CPP FAM BASE FUEL
412330	REG RES CPP FAM AA FUEL COST
412350	REG RES CPP NON FUEL ENERGY PEAK
412360	REG RES CPP NON FUEL ENERGY OFF PEAK
412370	REG RES CPP DSM COST RECOVERY RIDER

412510	REG SMALL GEN TIME OF USE NON FUEL DEMAND BASE
412520	REG SMALL GEN TIME OF USE NON FUEL ENERGY ALLHOURS
412530	REG SMALL GEN TIME OF USE FAM BASE FUEL
412540	REG SMALL GEN TIME OF USE FAM AA FUEL COST
412560	REG SMALL GEN TIME OF USE NON FUEL ENERGY PEAK
412570	REG SMALL GEN TIME OF USE NON FUEL ENERGY OFF PEAK
412580	REG SMALL GEN TIME OF USE DSM COST RECOVERY RIDER
412610	REG SMALL GEN TIME OF USE DSM BA COST
412710	REG SMALL GEN CPP NON FUEL DEMAND BASE
412715	REG SMALL GEN CPP DSM BA COST
412720	REG SMALL GEN CPP FAM BASE FUEL
412730	REG SMALL GEN CPP FAM AA FUEL COST
412750	REG SMALL GEN CPP NON FUEL ENERGY PEAK
412760	REG SMALL GEN CPP NON FUEL ENERGY OFF PEAK
412770	REG SMALL GEN CPP DSM COST RECOVERY RIDER
413110	REG RES NON FUEL DEMAND BASE
413120	REG RES NON FUEL ENERGY
413130	REG RES FAM BASE FUEL
413140	REG RES FAM AA FUEL COST
413150	REG RES FAM BA FUEL COST
413160	REG RES DSM COST RECOVERY RIDER
413170	REG RES IN PROVINCE
413190	REG RES DSM BA COST
413210	REG RES ACCRUED NON FUEL DEMAND BASE
413230	REG RES ACCRUED FAM BASE FUEL
413240	REG RES ACCRUED FAM AA FUEL COST
413250	REG RES ACCRUED FAM BA FUEL COST
413270	REG RES ACCRUED DSM COST
413280	REG RES ACCRUED DSM BA COST
413310	REG METERED OUTDOOR REC LIGHTS NON FUEL ENERGY
413330	REG METERED OUTDOOR REC LIGHTS FAM AA FUEL COST
413350	REG METERED OUTDOOR REC LIGHTS DSM COST RECOVERY RIDER
413410	REG TIME OF USE NON FUEL DEMAND BASE
413415	REG RES TIME OF DAY DSM BA COST
413420	REG TIME OF USE NON FUEL ENERGY
413430	REG TIME OF USE FAM BASE FUEL
413440	REG TIME OF USE FAM AA FUEL COST
413450	REG TIME OF USE FAM BA FUEL COST
413460	REG TIME OF USE NON FUEL ENERGY PEAK
413470	REG TIME OF USE NON FUEL ENERGY OFF PEAK
413480	REG RES TIME OF DAY DSM COST RECOVERY RIDER
413490	REG TIME OF USE REVENUE
413510	REG TIME OF USE ACCRUED NON FUEL DEMAND BASE
413530	REG TIME OF USE ACCRUED FAM BASE FUEL
413540	REG TIME OF USE ACCRUED FAM AA FUEL COST

413550	REG TIME OF USE ACCRUED FAM BA FUEL COST
413570	REG RES TIME OF DAY ACCRUED DSM COST
413580	REG RES TIME OF DAY ACCRUED DSM BA COST
414020	REG MURB REVENUE ENERGY
414030	REG MURB NON FUEL ENERGY
414050	REG MURB FAM AA FUEL COST
414070	REG MURB DSM COST RECOVERY RIDER
414110	REG SMALL GEN NON FUEL DEMAND BASE
414120	REG SMALL GEN NON FUEL ENERGY
414130	REG SMALL GEN FAM BASE FUEL
414140	REG SMALL GEN FAM AA FUEL COST
414150	REG SMALL GEN FAM BA FUEL COST
414160	REG SMALL GEN DSM COST RECOVERY RIDER
414180	REG SMALL GEN REVENUE
414190	REG SMALL GEN DSM BA COST
414210	REG SMALL GEN ACCRUED NON FUEL DEMAND BASE
414230	REG SMALL GEN ACCRUED FAM BASE FUEL
414240	REG SMALL GEN ACCRUED FAM AA FUEL COST
414250	REG SMALL GEN ACCRUED FAM BA FUEL COST
414270	REG SMALL GEN ACCRUED DSM COST
414280	REG SMALL GEN ACCRUED DSM BA COST
414310	REG GEN NON FUEL DEMAND BASE
414320	REG GEN NON FUEL ENERGY
414330	REG GEN FAM BASE FUEL
414340	REG GEN FAM AA FUEL COST
414350	REG GEN FAM BA FUEL COST
414360	REG GEN DSM COST RECOVERY RIDER
414380	REG GEN REVENUE
414390	REG GEN DSM BA COST
414410	REG GEN ACCRUED NON FUEL DEMAND BASE
414430	REG GEN ACCRUED FAM BASE FUEL
414440	REG GEN ACCRUED FAM AA FUEL COST
414450	REG GEN ACCRUED FAM BA FUEL COST
414460	REG GEN ACCRUED REV
414470	REG GEN ACCRUED DSM COST
414480	REG GEN ACCRUED DSM BA COST
414510	REG LARGE GENERAL NON FUEL DEMAND BASE
414520	REG LARGE GENERAL NON FUEL ENERGY
414530	REG LARGE GENERAL FAM BASE FUEL
414540	REG LARGE GENERAL FAM AA FUEL COST
414550	REG LARGE GENERAL FAM BA FUEL COST
414570	REG LARGE GENERAL DSM COST
414580	REG LARGE GENERAL DSM BA COST
414610	REG GENERAL TIME OF USE NON FUEL DEMAND BASE
414620	REG GENERAL TIME OF USE NON FUEL ENERGY ALLHOURS

414630	REG GENERAL TIME OF USE FAM BASE FUEL
414640	REG GENERAL TIME OF USE FAM AA FUEL COST
414660	REG GENERAL TIME OF USE NON FUEL ENERGY PEAK
414670	REG GENERAL TIME OF USE NON FUEL ENERGY OFF PEAK
414680	REG GENERAL TIME OF USE DSM COST RECOVERY RIDER
414710	REG GENERAL TIME OF USE DSM BA COST
414810	REG GENERAL CPP NON FUEL DEMAND BASE
414820	REG GENERAL CPP FAM BASE FUEL
414830	REG GENERAL CPP FAM AA FUEL COST
414850	REG GENERAL CPP NON FUEL ENERGY PEAK
414860	REG GENERAL CPP NON FUEL ENERGY OFF PEAK
414870	REG GENERAL CPP DSM COST RECOVERY RIDER
414900	REG GENERAL CPP DSM BA COST
415110	REG SMALL IND NON FUEL DEMAND BASE
415120	REG SMALL IND NON FUEL ENERGY
415130	REG SMALL IND FAM BASE FUEL
415140	REG SMALL IND FAM AA FUEL COST
415150	REG SMALL IND FAM BA FUEL COST
415160	REG SMALL IND DSM COST RECOVERY RIDER
415180	REG SMALL IND REVENUE
415190	REG SMALL IND DSM BA COST
415210	REG SMALL IND ACCRUED NON FUEL DEMAND BASE
415230	REG SMALL IND ACCRUED FAM BASE FUEL
415240	REG SMALL IND ACCRUED FAM AA FUEL COST
415250	REG SMALL IND ACCRUED FAM BA FUEL COST
415270	REG SMALL IND ACCRUED DSM COST
415280	REG SMALL IND ACCRUED DSM BA COST
415310	REG MEDIUM IND NON FUEL DEMAND BASE
415320	REG MEDIUM IND NON FUEL ENERGY
415330	REG MEDIUM IND FAM BASE FUEL
415340	REG MEDIUM IND FAM AA FUEL COST
415350	REG MEDIUM IND FAM BA FUEL COST
415360	REG MEDIUM IND REVENUE
415380	REG MEDIUM IND DSM COST
415390	REG MEDIUM IND DSM BA COST
415410	REG MEDIUM IND ACCRUED NON FUEL DEMAND BASE
415430	REG MEDIUM IND ACCRUED FAM BASE FUEL
415440	REG MEDIUM IND ACCRUED FAM AA FUEL COST
415450	REG MEDIUM IND ACCRUED FAM BA FUEL COST
415470	REG MEDIUM IND ACCRUED DSM COST
415480	REG MEDIUM IND ACCRUED DSM BA COST
415510	REG LARGE IND NON FUEL DEMAND BASE
415520	REG LARGE IND NON FUEL ENERGY
415530	REG LARGE IND FAM BASE FUEL
415540	REG LARGE IND FAM AA FUEL COST

415550	REG LARGE IND FAM BA FUEL COST
415570	REG LARGE IND DSM COST
415580	REG LARGE IND DSM BA COST
415590	REG LARGE IND DISTRIBUTION ADDER
415610	REG LARGE IND INTERRUPT RIDER NON FUEL DEMAND BASE
415615	REG LARGE IND INTERRUPT RIDER DISTRIBUTION ADDER
415620	REG LARGE IND INTERRUPT RIDER NON FUEL ENERGY
415630	REG LARGE IND INTERRUPT RIDER FAM BASE FUEL
415640	REG LARGE IND INTERRUPT RIDER FAM AA FUEL COST
415650	REG LARGE IND INTERRUPT RIDER FAM BA FUEL COST
415660	REG LARGE IND INTERRUPT RIDER REVENUE
415680	REG LARGE IND INTERRUPT RIDER DSM COST
415690	REG LARGE IND INTERRUPT RIDER DSM BA COST
415710	REG LARGE IND WHSLE MARKET BACKUPTOP UP NON FUEL DEMAND BASE
415720	REG LARGE IND WHSLE MARKET BACKUPTOP UP FAM BASE FUEL
415730	REG LARGE IND WHSLE MARKET BACKUPTOP UP
415760	REG LARGE IND WHSLE MARKET SUPPLIER SPILL NON FUEL DEMAND BASE
415780	REG LARGE IND WHSLE MARKET SUPPLIER SPILL REV
415810	REG LOAD RETENTION NON FUEL ENERGY
415820	REG LOAD RETENTION FAM BASE FUEL
415830	REG LOAD RETENTION
415855	REG SHORE POWER DSM BA COST
415860	REG SHORE POWER NON FUEL ENERGY
415870	REG SHORE POWER FAM BASE FUEL
415880	REG SHORE POWER DISTRIBUTION
415900	REG GRLF REPLACEMENT LOAD FOLLOWING REVENUE
415910	REG MERSEY
415920	REG TIME OF USE REAL TIME PRICE
415960	REG GRLF REPLACEMENT LOAD FOLLOWING DSM COST
415970	REG GRLF REPLACEMENT LOAD FOLLOWING DSM BA COST
415980	REG TIME OF USE REAL TIME PRICE DSM COST
415990	REG TIME OF USE REAL TIME PRICE DSM BA COST
416110	REG UNMETERED NON FUEL ENERGY
416120	REG UNMETERED FAM BASE FUEL
416130	REG UNMETERED FAM AA FUEL COST
416140	REG UNMETERED FAM BA FUEL COST
416150	REG UNMETERED DSM COST RECOVERY RIDER
416160	REG UNMETERED FAM CLEARING
416170	REG UNMETERED REVENUE
416190	REG UNMETERED DSM BA COST
416210	REG UNMETERED ACCRUED NON FUEL DEMAND BASE
416230	REG UNMETERED ACCRUED FAM BASE FUEL
416240	REG UNMETERED ACCRUED FAM AA FUEL COST
416250	REG UNMETERED ACCRUED FAM BA FUEL COST
416270	REG UNMETERED ACCRUED DSM COST

416280	REG UNMETERED ACCRUED DSM BA COST
416310	REG MUNICIPAL NON FUEL DEMAND BASE
416315	REG MUNICIPAL DSM BA COST
416320	REG MUNICIPAL NON FUEL ENERGY
416330	REG MUNICIPAL FAM BASE FUEL
416340	REG MUNICIPAL FAM AA FUEL COST
416350	REG MUNICIPAL FAM BA FUEL COST
416360	REG MUNICIPAL FAM CLEARING
416370	REG MUNICIPAL REV
416390	REG MUNICIPAL DSM COST
416660	REG MARITIME LINK FUEL CREDIT
417210	REG OATT PTP FIRM
417220	REG OATT PTP NON FIRM
417230	REG OATT SCHEDULING
417240	REG OATT REACTIVE CONTROL
417250	REG OATT REGULATION
417260	REG OATT LOAD FOLLOWING
417270	REG OATT ENERGY IMBALANCE
417280	REG OATT OPERATIVE RESERVE
417290	REG OATT NETWORK SERVICES
417295	REG DSM OATT MUNICIPAL
417300	REG GRID SALES REVENUE
417500	REG CONNECTION CHARGES
417550	REG LATE PAYMENT CHARGES
417600	REG NSF CHEQUE CHARGES
417650	REG COLLECTION CHARGES
417850	REG BY PRODUCT SALES
417910	REG RETAIL SALES ETS
417920	REG RETAIL SALES EIS
417950	REG RETAIL SALES GREEN POWER
418050	REG RENTAL REVENUE
418100	REG STEAM SALES
418150	REG MISC REV TEMP SERVICE TO PERMANENT
418210	REG MISC REVENUE METER REMOVAL
418220	REG MISC REV COMMUNITY SOLAR PROGRAM
418250	REG WIRING INSPECTION REVENUE
418300	REG MISC REVENUE FACILITIES
418350	REG MISC REVENUE RENT LOWER WATER ST
418410	REG OTHER REV TD MISC PROJECT BILLINGS
418420	REG OTHER REV EXTERNAL CUST METER SEALING
418430	REG OTHER REV ALIANT INITIATIVE
418440	REG OTHER REV CATV ATTACHMENT
418450	REG OTHER REV ALIANT MAKE READY

418460	REG OTHER REV PRDI
418470	REG OTHER REV PARKING LWS
418480	REG OTHER REV NSPI FITNESS
418490	REG OTHER REV GIP FINAL COSTED
418500	REG OTHER REV HRSB SMART METER
418510	REG OTHER REV MUNICIPALITY OWNED STREET LIGHTS
418530	REG OTHER REVENUE OTHER
421100	REG MISC REVENUE
421450	REG GAS OTHER REVENUES
451050	AFUDC EQUITY
452050	AMORTIZATION OF DEFEASANCE
453050	FOREIGN EXCHANGE 3RD PARTY
453100	FOREIGN EXCHANGE GAIN LOSS FAM
453350	REALIZED GAIN LOSS
453400	PO RATE VARIANCE GAIN LOSS
453450	UNREALIZED GAIN LOSS
455110	PENSION NON CURRENT SERVICE COST
455120	PENSION NON CURRENT SERVICE COST RECOVERY
455300	OTHER INCOME SALVAGE
455350	OTHER INCOME MISC REVENUE
502050	REG FUEL GAS CONSUMED
502100	REG FUEL GAS CONSUMED FX
502150	REG FUEL GAS CONSUMED COMMODITY DERIV
502160	REG FUEL GAS SOLD
502170	REG FUEL GAS PIPELINE LOSSES
502200	REG NATURAL GAS PIPELINE TOLL
502250	REG FUEL COAL CONSUMED
502260	REG FUEL COAL CONSUMED IMPORT
502270	REG FUEL COAL CONSUMED DOMESTIC
502280	REG FUEL COAL CONSUMED PETCOKE
502300	REG FUEL COAL CONSUMED FX
502350	REG FUEL COAL CONSUMED FUEL TESTING
502380	REG FUEL BIOMASS CONSUMED
502400	REG FUEL BUNKER C CONSUMED
502450	REG FUEL BUNKER C CONSUMED FX
502460	REG FUEL BUNKER C CONSUMED COMMODITY DERIV
502500	REG FUEL DIESEL OIL CONSUMED
502550	REG FUEL LIGHT OIL CONSUMED
502600	REG FUEL ADDITIVES CONSUMED
502650	REG FUEL LIMESTONE CONSUMED
502700	REG PURCHASED POWER
502720	REG PURCHASED POWER NET METERING
502750	REG PURCHASED POWER FX

502800	REG PURCHASED POWER COMMODITY DERIV
502850	REG PURCHASED POWER IPP PRE 2001
502900	REG PURCHASED POWER IPP POST 2001
502950	REG PURCHASED POWER COMFIT SMALL
503050	REG PURCHASED POWER COMFIT LARGE
503060	REG PURCHASEED POWER MARITIME LINK
503200	REG NATURAL GAS REVENUE
503250	REG NATURAL GAS REVENUE FX
503300	REG WIND RECEIVABLES PURCHASED POWER
503350	REG WIND RECEIVABLES FUEL FOR GENERATION
503400	REG EMISSION ALLOWANCE EXPENSE
504050	REG GRID SALES FUEL COAL CONSUMED
504100	REG GRID SALES FUEL BUNKER C CONSUMED
504200	REG GRID SALES MERCURY SORBENT
504250	REG GRID SALES MERCURY SORBENT FX
504300	REG GRID SALES PURCHASED POWER
504400	REG GRID SALES FUEL NATURAL GAS
504410	REG GRID SALES FUEL NATURAL GAS CLEARING
504450	REG GRID SALES FUEL DIESEL
505050	REG FUEL AFFILIATES
507050	REG FAM INCENTIVE
507100	REG FUEL ADJUSTMENT
507150	REG FIXED COST RECOVERY ADJUSTMENT
507200	REG RATE STABILIZATION ADJ FIXED COST RECOVERY
507250	REG DSM DEFERRAL
507300	REG DSM EXPENSE
530050	REGULAR LABOUR
530060	REGULAR LABOUR PAID TIME OFF
530100	REGULAR LABOUR PREFERRED COMPENSATION UNITS
530200	OVERTIME LABOUR
530210	OVERTIME LABOUR PAID TIME OFF
530250	SALES COMMISSION SALARIES
530300	TERM LABOUR
530310	TERM LABOUR PAID TIME OFF
530320	TERM LABOUR OVERTIME
530350	LOANED OPERATING LABOUR
530360	BORROWED OPERATING LABOUR
530400	LOANED CAPITAL LABOUR
530450	GROUP BENEFITS
530550	LABOUR CLEARING
530600	INCENTIVE BONUS
530650	REGULAR LABOUR INCENTIVE
530750	VACATION EXPENSE

530800	EE COMMON SHARE PURCHASE PLAN
530850	SEVERANCE COSTS
530900	OFFICE SUPPLIES
530950	TRAVEL EXPENSE
531100	IEXPENSES CAR RENTAL
531150	IEXPENSES TAXI
531200	IEXPENSES ACCOMMODATIONS
531250	IEXPENSES HOTEL ROOM TAX
531300	IEXPENSES KMS MILAGE
531350	IEXPENSES AIRFARE
531400	MATERIALS
531450	MATERIALS SAFETY PROMOTION
531500	MATERIALS CORPORATE PROMOTIONAL ITEMS
531510	MATERIALS ASH DISPOSAL
531550	CONTRACTS
531600	CONTRACTS SHARE SERVICE ALLOCATIONS
531650	CONTRACTS LTSA
531700	CONTRACTS CUSTOMER COMPLAINTS
531710	CONTRACTS ASH DISPOSAL
531750	SECURITY
531800	FREIGHT POSTAGE DELIVERY SHREDDING
531850	CHEMICALS
531900	RECYCLINGSHREDDING
531950	WATER
532050	CLEANING
532100	TELEPHONES
532150	TELEPHONE CELLULAR
532200	TOOLS EQUIPMENT
532250	LEASING
532300	LAND LEASES
532310	SHORT TERM LEASE EXPENSE - OPERATING LEASE
532320	LONG TERM LEASE EXPENSE - OPERATING LEASE
532330	VARIABLE LEASE EXPENSE - OPERATING LEASE
532350	SPONSOR OTHER DONATIONS
532400	SPONSOR OTHER DONATIONS SCHOLARSHIPS
532450	CORPORATE FILING FEES
532500	CONSULTING
532550	CONSULTING SHARE SERVICE ALLOCATIONS
532600	MEMBERSHIP DUES
532650	LUBRICANTS
532700	FLEET FUEL
532750	SUBSCRIPTION INFO SOFTWARE
532800	INTERNET COMMUNICATIONS

532850	APPLICATION SOFTWARE
532900	COMPUTER HARDWARE OPERATING SOFTWARE
532950	DIRECTORS FEES EXPENSES
533050	DIRECTORS COMPENSATION UNITS
533100	EXTERNAL LEGAL AUDIT
533150	ANNUAL SHAREHOLDERS MEETING
533200	ANNUAL SHAREHOLDER MEETING SHARE SERVICE ALLOCATIONS
533250	DONATIONS
533300	DONATIONS GOOD NEIGHBOUR FUND
533350	ADVERTISING
533400	MEALS ENTERTAINMENT
533410	OVERTIME MEALS
533450	EXPENSES TIPS
533500	EMPLOYEE BENEFITS
533510	EMPLOYEE BENEFITS ALLOCATION
533520	EMPLOYEE BENEFITS GENERAL
533525	EMPLOYEE BENEFITS LTD
533550	INSURANCE
533700	CORPORATE CREDIT CARD CLEARING
533750	RENT
533800	FLEET REPAIRS
533850	NON REGULATORY COST RECOVERY
533900	COST RECOVERY
533950	COST RECOVERY PREFERRED COMPENSATION UNITS
534100	COST RECOVERY EXECUTIVE STOCK OPTION PLAN
534500	INTERNAL SERVICES RECEIVED
534550	WARRANTY SERVICE CONTRACTS
534600	WARRANTY SERVICE CONTRACTS CUSTOMER GOODWILL
534650	TRAINING DEVELOPMENT
534700	CORPORATE SUPPORT ALLOCATION
534750	PERSONAL EQUIPMENT
534800	COMMISSIONS
534850	WRITE OFFS
534950	CUSTOMER RECOVERY
535100	OTHER GOODS SERVICES
535150	PREFERRED COMPENSATION UNITS
535200	EXECUTIVE STOCK OPTION PLAN
535300	SHARE SERVICE ALLOCATIONS
535350	DEFERRED COMPENSATION UNITS
535400	DIRECTORS COMPENSATION UNITS
535450	ASH DISPOSAL
535500	SHORT TERM INTEREST
535550	BANK CHARGES MISC INTEREST

535600	TAX ASSESSMENT
535650	VEHICLE ALLOCATED COSTS
535700	ADMIN OVERHEADS
535705	ADMIN OVERHEADS CONTRACTOR
535800	HEALTH SAFETY
535850	MISC REVENUE
535860	MISC REVENUE - EASTLINK
535900	GASES
535950	ROYALTIES EASEMENTS APPRAISALS
536050	DATA COMMUNICATION CIRCUITS
536100	RENTAL AND MAINTENANCE OF EQUIPMENT
536150	REPAIRS MAINTENANCE
536200	ENERGY USE NON ELECTRIC
536250	PENSIONER BENEFITS
536300	GEN COST RECOVERY
536350	GEN COST RECOVERY PARKING LOWER WATER STREET
536500	SPECTRA OM COSTS
536550	PO RATE VARIANCE RECOVERIES
536650	THIRD PARTY CLAIMS
536700	RELOCATION EXPENSE
536900	HEALTH WELLNESS
560050	GRANTS IN LIEU OF TAXES
562050	DEPRECIATION EXPENSE
562100	ACCRETION EXPENSE
563050	AMORTIZATION OF DEFERRED TAXES
563100	REGULATORY AMORTIZATION UNUSUAL ITEMS DEFERRALS ETC
563110	AMORTIZATION OF HYDRO GENERATION FACILITIES
564050	AMORTIZATION OF STREETLIGHT STRANDED ASSET
565100	COGS MATERIAL
565150	COGS INSTALLATION
565250	COST VARIANCE
565350	DISCOUNT TAKEN
565400	RETROACTIVE PRICE ADJUSTMENT
565450	NON ASSET INVENTORY EXPENSE
600100	INTEREST EXPENSE NSPI
600200	LONG TERM DEBT INTEREST
600500	NSPI BOND PREMIUMDISCOUNT EXPENSE
600550	ISSUE COSTS
601050	SHORT TERM INTEREST STD
602050	BANK CHARGES MISC INTEREST
602100	OTHER INTEREST EXPENSE
604050	INTEREST INCOME
604100	INTEREST INCOME MS RESIDENTIAL FINANCING
604120	INTEREST INCOME DSM

604150	INTEREST INCOME HEAT PUMPS PROGRAM
604200	INTEREST INCOME MS COMMERCIAL FINANCING
604250	INTEREST INCOME REG DEFERRAL FOR RENEWABLE TO RETAIL
604260	INTEREST INCOME ETS
604450	INTEREST CAPITALIZED FAM
604500	INTEREST CAPITALIZED FIXED COST RECOVERY
605050	AFUDC INTEREST
611050	INCOME TAX EXPENSE CURRENT
612050	INCOME TAX EXPENSE FUTURE
613100	INCOME TAX EXPENSE FUTURE FAM
660150	PREFERRED DIVIDENDS

LINE OF BUSINESS SEGMENT

Line of Business Segment Value	Line of Business Segment Description
000	DEFAULT
011	SOLID FUEL
012	NATURAL GAS
013	OIL
019	THERMAL GENERAL
021	WIND
022	HYDRO
023	TIDAL
024	BIOMASS
025	SOLAR
029	RENEWABLES GENERAL
091	BY PRODUCT SERVICES
099	POWER GENERATION GENERAL
111	SUBSTATION OPERATIONS TRANSMISSION
119	TRANSMISSION GENERAL
121	SUBSTATION OPERATIONS DISTRIBUTION
122	FIELD OPERATIONS PLT
123	METER AND INSPECTION SERVICES
129	DISTRIBUTION GENERAL
131	EV CHARGING
139	REGIONAL MARKETING GENERAL
149	CUSTOMER ACCOUNTS GENERAL
159	CUSTOMER SERVICE ELECTRIC
171	RELIABILITY
199	TRANSMISSION AND DISTRIBUTION GENERAL
239	UTILITY SERVICES GENERAL

241	SHARED SERVICES
900	CORPORATE

LOCATION SEGMENT

Location Segment Value	Location Segment Description
0000	DEFAULT
1101	LOWER WATER STREET
1102	TERMINAL ROAD
1103	BAYERS ROAD
1104	LAKESIDE
1106	PURDYS WHARF
1110	PROVINCIAL ENERGY VENTURES STORAGE
1111	LINGAN LONG TERM DEBT STORAGE
1112	BEARS HEAD
1113	POINT TUPPER MARINE TERMINAL
1114	INTERNATIONAL COAL PIER
1131	LINGAN UNIT 1
1132	LINGAN UNIT 2
1133	LINGAN UNIT 3
1134	LINGAN UNIT 4
1138	LINGAN COMMON PLANT
1139	LINGAN GENERAL
1141	POINT ACONI UNIT 1
1148	POINT ACONI COMMON PLANT
1149	POINT ACONI GENERAL
1152	POINT TUPPER UNIT 2
1158	POINT TUPPER COMMON PLANT
1159	POINT TUPPER GENERAL
1165	TRENTON UNIT 5
1166	TRENTON UNIT 6
1168	TRENTON COMMON PLANT
1169	TRENTON GENERAL
1171	TUFTS COVE UNIT 1
1172	TUFTS COVE UNIT 2
1173	TUFTS COVE UNIT 3
1174	TUFTS COVE UNIT 4
1175	TUFTS COVE UNIT 5
1176	TUFTS COVE UNIT 6
1177	AUXILIARY BOILER UNIT 1

1178	TUFTS COVE COMMON PLANT
1179	TUFTS COVE GENERAL
1180	LM BUILDING
1191	TUSKET UNIT 1
1198	TUSKET COMMON PLANT
1199	TUSKET GENERAL
1201	VICTORIA UNIT 1
1202	VICTORIA UNIT 2
1208	VICTORIA COMMON PLANT
1209	VICTORIA JUNCTION GENERAL
1211	BURNSIDE UNIT 1
1212	BURNSIDE UNIT 2
1213	BURNSIDE UNIT 3
1214	BURNSIDE UNIT 4
1218	BURNSIDE COMMON PLANT
1219	BURNSIDE GENERAL
1297	STEAM GENERAL
1298	GAS GENERAL
1299	POWER GENERATION GENERAL
1300	DIGBY NECK
1301	GRAND ETANG
1302	LITTLE BROOK
1303	NUTTBY
1304	SABLE
1305	SOUTH CANOE NEW ROSS
1306	POINT TUPPER RESL
1307	POINT TUPPER 3 RESL
1308	BROOKLYN POWER IPP
1309	CAPE SHARPE IPP
1310	WIND GENERAL
1350	AVON
1351	BEAR RIVER
1352	BLACK RIVER
1353	DICKIE BROOK
1354	FALL RIVER
1355	HARMONY
1356	LEQUILLE
1357	MERSEY
1358	PARADISE
1359	SHEET HARBOUR
1360	ST MARGARETS BAY
1361	WRECK COVE
1362	NICTAUX PARADISE

1363	ROSEWAY AND HARMONY
1364	SISSIBOO WEYMOUTH
1365	MILTON
1366	WHITE ROCK
1367	TUSKET RIVER
1370	HYDRO GENERAL
1380	ANNAPOLIS
1401	PORT HAWKESBURY UNIT 1
1408	PORT HAWKESBURY COMMON PLANT
1409	PORT HAWKESBURY GENERAL
1410	BIOMASS GENERAL
1450	CENTRAL
1451	EAST
1452	METRO
1453	NORTH EAST
1454	WEST
1455	TRANSMISSION GENERAL
1456	DISTRIBUTION GENERAL
1457	RAGGED LAKE
1460	T AND D GENERAL
1500	NOVA SCOTIA GENERAL
1550	SOLAR GENERAL

COST CENTRE SEGMENT

Cost Centre Segment Value	Cost Centre Segment Description
000	DEFAULT
001	MAINTENANCE
002	OPERATIONS
003	ADMINISTRATION
004	ENVIRONMENT
005	SAFETY
006	PROCUREMENT
007	CUSTOMER CARE CENTRE
008	HUMAN RESOURCES
009	BILLING SERVICES
010	FACILITIES
011	ENGINEERING
012	FINANCE
014	FLEET SERVICES

015	FUEL HANDLING
016	ACCOUNTING
017	MARKETING
018	PENSION ADMINISTRATION
019	FORESTRY AND VEG MANAGEMENT
020	MAJOR DEVELOPMENTS
022	TRADING
023	FUELS FINANCE
024	ASSET MANAGEMENT
025	TAX
026	SYSTEM MAINTENANCE
027	SYSTEM PLANNING AND OPTIMIZATION
029	TREASURY
030	LEGAL
031	PLANNING
032	SECURITY
033	RESOURCE MANAGEMENT
034	CONTROLLER
035	INFORMATION TECHNOLOGY
036	TECHNICAL SERVICES
037	TALENT ACQUISITION
038	GENERATION ASSET MANAGEMENT
039	GENERATION SERVICES
040	OFFICE OF THE CEO
041	OFFICE OF THE CFO
044	CORPORATE AFFAIRS
045	ENTERPRISE RISK MANAGEMENT
046	METER READING
047	CREDIT SERVICES
048	CORPORATE SECRETARY
049	CORPORATE INSURANCE
050	REGULATORY AFFAIRS
051	ENERGY FUELS AND RISK MGMT.
054	INSPECTION PROGRAM
056	VP FINANCE
057	CHEM LAB AND ENVIRONMENTAL
058	PAYMENT SERVICES
059	PAYROLL
060	METER SERVICES
061	INVESTOR RELATIONS
064	UTILITY SERVICES
065	MERGERS AND ACQUISITIONS
066	ORIGINATION
067	INTERNAL AUDIT

068	FUELS PORTFOLIO OPTIMIZATION
069	PROJECTS
071	ENERGY EFFICIENCY
072	DIRECTOR OF SAFETY
073	EMPLOYEE SERVICES
074	CONTROL CENTRE OPERATIONS
077	DIRECTOR PLANT OPS
079	DIRECTOR OF HUMAN RESOURCES
080	TECHNICAL AND CONSTRUCTION SERVICES
083	OPERATING SYSTEMS AND DOCUMENT CONTROL
084	FINANCIAL ANALYSIS
085	CORPORATE ADJUSTMENTS AND ALLOCATIONS
086	EXECUTIVE MANAGEMENT
087	VP INTEGRATION
089	MARITIME LINK INTEGRATION
090	TRANSMISSION LINE
091	CAPITAL PLANNING AND EXECUTION
092	COMMUNICATIONS AND PUBLIC AFFAIRS
093	CAPITAL MANAGEMENT AND PERFORMANCE
094	PETC PROTECTION EQUIPMENT TEST CENTRE
095	TELECOM
096	COMMERCIAL SOLUTIONS
098	WAREHOUSE OPERATIONS
099	WIRE INSPECTION SERVICE
100	APPRENT. LINE TECHNICIANS
101	STRATEGIC DEVELOPMENT
102	CAPITAL ACCOUNTING AND ANALYSIS
103	PROCUREMENT AND REAL ESTATE
105	ACCOUNTS PAYABLE
106	INTERCONNECTION STUDIES CCO TARIFFS
107	STRATEGIC INITIATIVES
108	HEALTH AND WELLNESS
109	DELIVERY SERVICES
110	HR STRATEGIES GROUP
111	OFFICE OF THE COO
112	SECONDMENTS
113	WORK MANAGEMENT
114	EVP OPERATIONS
116	DOWNLINE RECLOSER SHOP
117	STORM
118	CUSTOMER SOLUTIONS
119	PROJECT IMPLEMENTATION
120	COMPLIANCE

121	CUSTOMER COMMUNICATIONS AND QUALITY ASSURANCE
122	OFFICE OF THE CDO
125	TRANSMISSION RELIABILITY AND ADMIN.
126	FITNESS CENTER
127	RESOURCE PLANNING GROUP
128	HEALTH PROMOTION
129	STRATEGIC PROCUREMENT
130	COMMERCIAL INVESTMENTS AND FINANCIAL ANALYSIS
134	BUSINESS INTELLIGENCE AND ANALYTICS
135	TECHNOLOGY SECURITY AND CYBER RISK MANAGEMENT
136	TECHNOLOGY PROJECT MANAGEMENT OFFICE
137	TECHNOLOGY ENTERPRISE ARCHITECT
138	TECHNOLOGY OPERATIONS
139	TECHNOLOGY INTEGRATED SUPPORT TEAM
140	TECHNOLOGY BUSINESS SUPPORT
141	TECHNOLOGY SERVICE DELIVERY
142	TECHNOLOGY TECHNICAL SUPPORT
145	HUMAN RESOURCE OPERATIONS
146	CHANGE MANAGEMENT
150	TECHNOLOGY STRATEGIC PLANNING
151	BUSINESS TRANSFORMATION
153	OFFICE OF THE CCEO
155	PERMIT CENTER
156	STAKEHOLDER ENGAGEMENT
158	WAM PRODUCT SUPPORT
160	DIVERSITY, EQUITY AND INCLUSION
161	BUSINESS VALUE TEAM
163	ERP PRODUCT SUPPORT
900	CAPITAL

COMPANY/INTERCOMPANY SEGMENT

Company/ Intercompany Segment Value	Company/Intercompany Segment Description
000	DEFAULT
001	NSPI
002	NSPI ASSIST 2017 INC
009	EMERA INC
012	ENERGY SERVICES
016	EE SERVICES US
017	EE US SUB 1
022	NSP PIPELINE

025	SCOTIA POWER US
033	CAYMAN 456 LTD
038	EMERA ENERGY LP
039	EMERA ENERGY LP HOLDCO
060	BAYSIDE POWER INC
061	BAYSIDE POWER LIMITED PARTNERSHIP
062	BROOKLYN POWER CORPORATION
064	BRIDGEPORT
065	TIVERTON
066	RUMFORD
080	NSP MARITIME LINK
081	ENL ISLAND LINK INC
082	EMERA NEWFOUNDLAND AND LABRADOR HOLDINGS INC
100	NOVA SCOTIA POWER ENERGY MARKETING INC
121	EUS HEAD OFFICE
130	EUS OPERATIONS
201	TECO ENERGY
202	TECO SERVICES INC
212	NEW MEXICO GAS COMPANY
221	TAMPA ELECTRIC
231	PEOPLE'S GAS
324	3240384 NOVA SCOTIA LIMITED
350	EMERA BRUNSWICK PIPELINE CO LTD
383	3065383 NS CO
389	EMERA REINSURANCE
390	EMERA US HOLDINGS
393	BANGOR HYDRO
394	EMERA ENERGY GENERATION
396	EMERA ENERGY GENERATION II
397	CLEAN POWER NORTH EAST DEVELOPMENT INC
402	EMERA US FINANCE LP
404	EMERA US FINANCE NO1 LLC
408	EUSHI FINANCE NO 1 LLC
410	EMERA TECHNOLOGIES INC
411	3325140 NOVA SCOTIA LIMITED
415	GRAND HVAC
654	3267654 NOVA SCOTIA LTD
851	GRAND BAHAMA POWER COMPANY
853	BARBADOS LIGHT AND POWER
854	THE BARBADOS LIGHT AND POWER COMPANY LIMITED
855	LIGHT AND POWER HOLDINGS
862	DOMINICA
922	3081922 NS LTD

**2025 Annual Financial Statements Attachment 9 has been
filed electronically.**

Nova Scotia Power Inc.
Rate Base
 Years Ended December 31st
 Millions of Dollars

RB-2-16

2025 Actual

1		
2		
3		Amount
4		
15	Net Plant in Service	5,045
447	Less: Impact of the Non-Regulated Adjustments	(84)
448	Plus: Construction work in progress	340
449	Net Utility Fixed Assets	5,302
450	Add:	
451	Deferred Charges & Credits	
461	Financing Charges	24
466	Pension Charges	143
468	FAM Deferral	102
471	Storm Rider Deferral	-
473	DSM Rider Deferral	1
532	Other General Charges	9
579	Asset Retirement Obligations	(144)
582	Cost of Removal Asset	17
587	Deferred income taxes on FAM, FCR, & RS	24
602	Other Deferred Credits	(46)
603	Total Deferrals and Credits	129
604		127
605	Long Term Receivable	127
606	Allowance for materials and supplies ²⁾	299
607	Allowance for Working Capital	
669	Accounts receivable - Total	573
682	Prepaid expenses - Total	20
727	Materials inventory - Total	113
761	Fuel inventory - Total	185
762	Allowance for materials and supplies ²⁾	(299)
937	Accounts payable and accruals - Total	(316)
940	Accrued Interest	(40)
993	Other Liabilities	(81)
1000	Income Tax Payable - Total	(0)
1004	Posted Margin	3
1005	Total Allowance for Working Capital	159
1006	Total Additions	714
1007		
1008	Regulated Rate Base	6,015
1009		
1010		
1011	Weighted average cost of debt and return on equity	5.71%
1012		
1034	Interest and Net Income	343.2
1035	Non-Current Service Pension Costs	(22.4)
1036	Less: AFUDC and FAM and FCR Interest	(16.8)
1059	Operating costs	1,379.0
1060	Depreciation and amortization	295.9
1061	Income taxes	(36.0)
1062	Total Revenue	1,942.9
1063		
1064		
1065	Net Revenue per Statement of Earnings	1,942.9

Notes:

- 1) Figures presented reflect whole numbers which may cause \$0.1M in rounding differences on some line items.
- 2) Allowance for materials and supplies is the ending balance as at December 31.

			Gross Book Value, beginning	Asset Additions	Asset Transfers	Asset Retirements	Total Reserve, beginning	Asset Retirements	Depreciation & Accretion Expense	Salvage & Cost of Removal	Reclassify to ARO and COR Liability	Adjustments	Net Regulated Plant In- Service, beginning	Net Regulated Plant In- Service, ending
2025 Property, Plant and Equipment Continuity Asset		Depreciation Rate												
Distribution Plant - D														
Distribution Plant - D	Land	0.00%	5	0	-	-	-	-	-	-	-	-	5	5
Distribution Plant - D	Land Rights	1.56%	149	26	-	(2)	(18)	2	(3)	(0)	0	(0)	131	154
Distribution Plant - D	Line Transformers	3.41%	600	48	-	(6)	(268)	6	(21)	4	(3)	(0)	332	360
Distribution Plant - D	Meters	6.87%	109	4	-	(0)	(37)	0	(8)	0	(0)	(0)	72	68
Distribution Plant - D	Overhead Conductors and Devices	3.33%	344	16	-	(2)	(158)	2	(12)	2	(0)	(0)	186	191
Distribution Plant - D	Poles, Towers and Fixtures	3.79%	681	46	-	(7)	(337)	7	(27)	3	4	0	345	372
Distribution Plant - D	Remote Monitoring Equipment	10.32%	0	0	-	-	(0)	-	-	(0)	0	-	0	0
Distribution Plant - D	SCADA Equipment	9.68%	0	(0)	-	-	(0)	-	-	-	-	0	(0)	(0)
Distribution Plant - D	Services	5.33%	155	3	-	(0)	(99)	0	(8)	1	2	0	56	54
Distribution Plant - D	Station Equipment	1.22%	75	1	-	(0)	(65)	0	(1)	0	(0)	(0)	10	9
Distribution Plant - D	Station Equipment - Miscellaneous	12.49%	13	6	-	(0)	(11)	0	(1)	(1)	1	(0)	2	6
Distribution Plant - D	Street Lighting	5.33%	60	4	-	(1)	(26)	1	(3)	0	0	(0)	34	36
Distribution Plant - D	Structures and Improvements	5.31%	2	0	-	-	(1)	-	(0)	(0)	0	-	2	2
Distribution Plant - D	Underground Conductors and Devices	3.17%	83	7	-	(1)	(31)	1	(3)	0	0	(0)	52	56
Distribution Plant - D	Underground Conduit	1.51%	9	0	-	(0)	(4)	0	(0)	0	(0)	0	4	4
Distribution Plant - D	Capital Contributions	3.89%	(103)	0	-	-	103	-	-	-	-	(0)	-	(0)
Distribution Plant - D	Smartgrid Solar	4.00%	1	0	-	-	(0)	-	(0)	-	-	(0)	1	1
Distribution Plant - D	Smartgrid Batteries	10.00%	1	0	-	-	(0)	-	(0)	-	-	0	1	0
Distribution Plant - D	Smartgrid Chargers	6.67%	0	0	-	-	0	-	0	-	-	-	1	1
Distribution Plant - D	Salvage Allowance	-	-	0	-	-	0	-	-	-	-	(0)	0	0
Distribution Plant - D	Site Restoration	-	0	-	-	-	(20)	-	(2)	-	0	(0)	(19)	(22)
Gas Turbine Generation Plant - G														
Gas Turbine Generation Plant - G	Burnside CT	2.18%	44	4	-	(0)	(15)	0	(1)	(0)	0	0	29	32
Gas Turbine Generation Plant - G	LM 6000 TC #4	2.43%	60	19	-	-	(3)	-	(2)	(0)	0	(0)	57	75
Gas Turbine Generation Plant - G	LM 6000 TC #5	2.64%	39	0	-	(0)	(4)	0	(1)	0	(0)	(0)	35	34
Gas Turbine Generation Plant - G	Tusket CT	5.26%	19	1	-	(0)	(9)	0	(1)	(0)	0	0	10	10
Gas Turbine Generation Plant - G	Victoria Junction CT	2.71%	21	0	-	(0)	(8)	0	(1)	(0)	0	(0)	13	13
General Plant - P														
General Plant - P	Communication Equipment	4.38%	94	2	-	-	(53)	-	(3)	(0)	0	-	41	40
General Plant - P	Communication Equipment - SCADA	1.33%	31	1	-	-	(11)	-	(0)	0	(0)	-	20	20
General Plant - P	Computer Hardware	20.00%	60	6	-	(0)	(44)	0	(6)	(1)	1	(1)	16	15
General Plant - P	Computer Software	10.00%	276	26	-	0	(105)	(0)	(28)	(2)	3	-	171	169
General Plant - P	Land	0.00%	10	0	-	-	(1)	-	-	-	-	1	9	10
General Plant - P	Land Rights	1.93%	5	0	-	-	(2)	-	(0)	-	-	-	4	4
General Plant - P	Mining Equipment	2.92%	2	-	-	-	(2)	-	(0)	-	0	-	0	0
General Plant - P	Miscellaneous Equipment	5.02%	63	3	-	-	(35)	-	(3)	0	(1)	(0)	28	28
General Plant - P	Office Furniture and Equipment	9.26%	9	0	-	-	(10)	-	(0)	-	-	-	(0)	(0)
General Plant - P	Remote Monitoring Equipment	10.27%	4	2	-	-	(3)	-	(0)	0	(0)	-	1	3
General Plant - P	Roads, Bridges and Trails	2.58%	1	-	-	-	(0)	-	(0)	-	-	-	0	0
General Plant - P	Stores Equipment	14.97%	0	-	-	-	(0)	-	-	-	-	-	-	-
General Plant - P	Structures and Improvements	2.85%	184	5	-	(0)	(73)	0	(5)	0	0	(0)	111	110
General Plant - P	Transportation Equipment	9.55%	109	21	-	(4)	(77)	4	(11)	(0)	(1)	-	31	40
General Plant - P	CBDC Rail Mtce	-	-	-	-	-	(1)	-	-	-	-	-	(1)	(1)
General Plant - P	Purchase Difference	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant - P	Capital Contributions	8.16%	(2)	0	-	-	2	-	-	-	-	-	0	0
General Plant - P	Salvage Allowance	8.16%	-	-	-	-	0	-	-	-	-	-	0	0
General Plant - P	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro Generation Plant - H														
Hydro Generation Plant - H	Annapolis Tidal	2.02%	40	2	-	(0)	(18)	0	(1)	2	(2)	(0)	22	24
Hydro Generation Plant - H	Avon	2.63%	20	0	-	(0)	(8)	0	(1)	0	0	0	13	13
Hydro Generation Plant - H	Bear River	1.57%	64	2	-	(0)	(14)	0	(1)	0	(0)	0	50	50
Hydro Generation Plant - H	Black River	1.77%	58	0	-	(0)	(15)	0	(1)	(0)	0	0	43	43
Hydro Generation Plant - H	Dickie Brook	2.75%	16	0	-	-	(3)	-	(1)	0	0	(0)	14	13
Hydro Generation Plant - H	Fall River	1.58%	2	0	-	-	(0)	-	(0)	(0)	0	0	2	2
Hydro Generation Plant - H	Harmony	3.96%	0	-	-	-	0	-	-	-	0	0	1	1
Hydro Generation Plant - H	Hydro General	2.10%	12	2	-	(0)	4	0	(0)	0	(0)	-	16	17
Hydro Generation Plant - H	Lequille	2.03%	44	6	-	(1)	(7)	1	(1)	0	(0)	0	37	42
Hydro Generation Plant - H	Mersey	2.00%	47	1	-	(1)	(17)	1	(1)	0	0	0	30	30
Hydro Generation Plant - H	Mersey & Milton Heavy Maintenance	2.10%	16	2	-	(0)	(2)	0	(0)	0	(0)	-	14	16
Hydro Generation Plant - H	Roseway	1.99%	0	-	-	-	0	-	-	0	(0)	0	0	0
Hydro Generation Plant - H	Sheet Harbour	2.94%	42	0	-	(0)	(11)	0	(1)	1	(0)	0	31	30
Hydro Generation Plant - H	St. Margaret's	2.48%	55	1	-	(0)	(14)	0	(2)	1	(1)	0	41	41
Hydro Generation Plant - H	Tusket	2.30%	24	1	-	(0)	(6)	0	(1)	0	(0)	0	18	19
Hydro Generation Plant - H	White Rock	2.10%	1	0	-	-	(0)	-	(0)	0	(0)	-	1	1
Hydro Generation Plant - H	Wreck Cove	1.45%	290	16	-	(0)	(81)	0	(5)	1	(1)	(0)	209	221
Steam Generation Plant - S														
Steam Generation Plant - S	International Coal Pier	2.60%	13	5	-	(3)	6	3	(0)	(0)	0	(0)	18	22
Steam Generation Plant - S	Lingan 1-2	4.00%	228	6	-	(1)	(216)	1	(9)	(1)	1	0	12	9
Steam Generation Plant - S	Lingan 3-4	2.15%	297	6	-	0	(180)	(0)	(7)	(1)	2	0	117	116
Steam Generation Plant - S	Lingan Common	4.23%	135	7	-	(1)	(30)	1	(7)	(1)	1	(0)	105	106
Steam Generation Plant - S	PH Biomass	2.50%	213	3	-	1	(46)	(1)	(5)	1	(1)	-	167	166
Steam Generation Plant - S	Point Aconi	2.20%	589	25	-	(4)	(265)	4	(13)	5	(3)	(1)	324	337
Steam Generation Plant - S	Point Tupper 1	3.45%	46	3	-	-	(6)	-	(2)	0	0	-	40	41
Steam Generation Plant - S	Point Tupper Common	2.45%	160	3	-	0	(98)	(0)	(5)	2	(1)	0	62	60
Steam Generation Plant - S	Point Tupper Marine Terminal	3.15%	38	1	-	(0)	(20)	0	(1)	(0)	0	(0)	18	18
Steam Generation Plant - S	Steam General	2.82%	12	-	-	-	(4)	-	(0)	0	0	-	8	8

REDACTED (CONFIDENTIAL INFORMATION REMOVED)														
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Steam Generation Plant - S	Trenton 5	3.01%	155	9	-	(1)	(77)	1	(5)	2	(2)	0	79	83
Steam Generation Plant - S	Trenton 6	2.17%	287	4	-	(1)	(140)	1	(7)	1	0	0	147	145
Steam Generation Plant - S	Trenton Common	0.44%	47	3	-	(0)	8	0	(0)	1	(1)	0	55	58
Steam Generation Plant - S	Tufts Cove 1	4.12%	55	9	-	(2)	(37)	2	(2)	0	(0)	0	18	24
Steam Generation Plant - S	Tufts Cove 2	3.57%	67	4	(0)	(0)	(31)	0	(3)	0	(0)	0	36	37
Steam Generation Plant - S	Tufts Cove 3	2.10%	93	3	-	(1)	(45)	1	(2)	0	(0)	0	48	50
Steam Generation Plant - S	Tufts Cove 6	3.03%	98	0	0	(0)	(36)	0	(3)	0	0	(0)	62	59
Steam Generation Plant - S	Tufts Cove Common	3.10%	98	5	-	(1)	(39)	1	(4)	0	0	0	59	60
Solar - E														
Solar - E	Solar	4.00%	2	-	-	-	(0)	-	(0)	-	-	-	1	1
Transmission Plant - T														
Transmission Plant - T	Land	0.00%	13	(0)	-	(0)	-	0	-	-	-	0	13	13
Transmission Plant - T	Land Rights	1.26%	104	3	-	(0)	(28)	0	(1)	(0)	0	(0)	76	78
Transmission Plant - T	Overhead Conductors and Devices	1.96%	185	6	-	(1)	(77)	1	(4)	1	(0)	(0)	109	111
Transmission Plant - T	Poles and Fixtures	4.32%	279	12	-	(2)	(70)	2	(12)	2	2	(0)	209	213
Transmission Plant - T	Roads, Trails and Bridges	1.74%	2	0	-	(0)	(0)	0	(0)	-	-	(0)	2	3
Transmission Plant - T	Station Equipment	2.14%	537	52	-	(1)	(241)	1	(12)	1	0	(0)	296	336
Transmission Plant - T	Structures and Improvements	2.14%	65	6	-	(0)	(18)	0	(1)	0	(0)	(0)	46	51
Transmission Plant - T	Towers and Fixtures	1.26%	113	3	-	(0)	(72)	0	(1)	0	(0)	(0)	42	43
Transmission Plant - T	Underground Conductors and Devices	2.61%	8	4	-	(0)	(1)	0	(0)	(0)	0	(0)	7	10
Transmission Plant - T	Underground Conduit	1.53%	2	0	-	-	(1)	-	(0)	(0)	0	-	1	1
Transmission Plant - T	Capital Contributions	2.35%	(33)	(0)	-	-	33	-	-	-	-	0	-	(0)
Transmission Plant - T	Salvage Allowance	-	-	(0)	-	-	0	-	-	-	-	0	0	0
Transmission Plant - T	Site Restoration	-	0	-	-	-	0	-	(2)	-	0	(0)	0	(2)
Transmission Plant - T	Energy Storage	5.00%	-	139	-	-	-	-	-	-	(0)	-	-	139
Wind Generation Plant - W														
Wind Generation Plant - W	Digby	4.00%	71	(0)	-	(0)	(30)	0	(3)	1	0	0	41	38
Wind Generation Plant - W	Nuttby	4.00%	114	0	-	-	(61)	-	(4)	0	0	0	53	49
Wind Generation Plant - W	Point Tupper	4.00%	26	0	-	-	(13)	-	(1)	0	0	0	12	11
Wind Generation Plant - W	Sable	4.00%	12	-	-	-	(5)	-	(0)	-	-	-	7	7
Wind Generation Plant - W	South Canoe	4.00%	98	1	-	-	(37)	-	(4)	(0)	(0)	0	61	57
Wind Generation Plant - W	Wind General	4.00%	1	1	-	-	1	-	(0)	0	0	0	2	3
Unapproved Spending Balances	Unapproved Spending Balances		(46)	(0)	-	-	8	-	1	(0)	-	0	(38)	(37)
			8,134	606	-	(45)	(3,485)	45	(290)	28	2	(1)	4,648	4,993

Regulated PP&E	4,993
Unregulated adjustments to PP&E:	
Lower Water St. Office	8
Tufts Cove 6 Non-Reg portion	1
Land At Tufts Cove & Goldboro	1
Kentville Electric PPD	2
Maritime Link Transmission	35
EV Charging Stations	3
Unapproved Spending (PPE)	1
Total Non-Regulated PP&E	52
Total PP&E	5,045
Total CWIP	340
Burnside Natural Gas Conversion	3
Unapproved Spending (CWIP)	29
Total Non-Regulated CWIP	32
Regulated CWIP	308
NBV per Legal Statements (PP&E & CWIP)	5,385
	(0.6)
Total Non-Regulated Cost of Removal (1)	(0.6)
Regulated NBV (PP&E & CWIP)	5,302

(1)The Non-Regulated Adjustments to Property Plant and Equipment (PP&E) in Attachment 9 include both Net Book Value and Cost of Removal incurred for non-regulated and unapproved projects. NS Power has determined the amount immaterial to present separately as a increase to the Cost of Removal Liability in Attachment 9, and rather has reduced the Net Book Value of PP&E. The accumulated Cost of Removal was approximately \$0.6M as at December 31, 2025, primarily associated with removal costs incurred for the Mersey Hydro Redevelopment Project, representing a regulatory asset.

Asset Retirement Obligation Continuity (\$ millions)	Balance at Dec 31, 2024	Liability Settlements	Revisions to estimated cash flows	Accretion Expense - US GAAP	Balance at Dec 31, 2025
Steam Plants	75.5	-	-	4.0	79.5
Hydro Plants	37.9	-	-	2.0	39.9
Gas Turbine	7.0	-	-	0.4	7.4
Wind Generation	15.2	-	-	0.8	16.0
PCB AROs	1.6	(0.9)	-	0.1	0.8
Total	137.2	(0.9)	-	7.3	143.6

2025 ARO Settled by Capital Item

\$ millions

<u>Funding Project Number</u>	<u>Funding Project Description</u>	<u>ARO Settled</u>
C0060749	2024 Padmount Replacment Program	(0.3)
23120-T003-820	PROVINCIAL-TRANS SUBSTATION PRIMARY	(0.1)
O0000370	Substation Ops Converted Projects	(0.1)
23361-D008-800	D008 Provincial Storm	(0.0)
C0043130	2022 Padmount Replacement Program	(0.0)
C0056240	2023-2024 Transmission Switch & Bre	(0.0)
23158-D005-800	D005 Unplanned Replace Deteriorated	(0.0)
23137-D055-800	D055 - Planned Replacement Of Distr	(0.0)
C0050836	2023 Padmount Replacement Program	(0.0)
16127-D004-623	Sack. Depot - New Cust. Replacement	(0.0)
O0000612	Northeast Distribution Work	(0.0)
39767-D061-623	New Customers - Residential CEN	(0.0)
O0000357	East Converted Ops Projects	(0.0)
C0006319	D-2019 PCB Pole Top Transformer Rep	(0.0)
O0000370	Substation Ops Converted Projects	(0.0)
C0043571	2022-2023 Transmission Switch & B	(0.0)
16131-D006-623	Sack. Depot - Regulatory Replacemen	(0.0)
C0011208	D-2019 Padmount Replacement Program	(0.0)
O0000394	Substation Ops Metro Transmission	(0.0)
O0000357	East Converted Ops Projects	(0.0)
O0000116	West Converted Ops Projects	(0.0)
O0000606	Northeast Converted Ops Projects	(0.0)
C0031166	2021 Downline PCB Replacements	(0.0)
C0021122	2020-21 Transmission Switch and Br	(0.0)
C0020835	2020 Padmount Replcement Program	(0.0)
C0031145	2021 Padmount Replacement Program	(0.0)
O0000393	Substation Ops East Transmission	(0.0)
O0000103	Metro Converted Ops Projects	(0.0)
C0043490	2022 Downline Asset PCB Replacement	(0.0)
C0031262	2021-22 Transmission Switch & Break	0.0
C0020834	2020-21 Inaccessible PCB Transf Rep	0.0
C0054995	2023 Inaccessible PCB Transf Rep	0.0
		(0.9)

2025 Cost of Removal Continuity	Balance at Dec 31 2024	COR Collected via		COR Incurred (Settled)	Balance at Dec 31 2025
		Depreciation Expense	Salvage ⁽¹⁾		
DISTRIBUTION	88.8	14.9		(10.5)	93.2
GAS TURBINE	(4.0)	0.1		0.4	(3.5)
GENERAL PLANT	(18.3)	(1.0)	0.1	2.6	(16.6)
HYDRO	(33.5)	0.4	0.0	(6.7)	(39.8)
STEAM	(60.3)	0.9		(10.3)	(69.7)
TRANSMISSION	20.7	4.9	0.1	(3.9)	21.8
WIND	(1.9)	0.0		(0.7)	(2.6)
TOTAL	(8.5)	20.1	0.2	(28.9)	(17.1)

(1) Subsequent to the close of NS Power's year end Financial Statements, it was noted that Salvage amounts collected for Distribution assets, approximately \$0.4M, was not transferred to the Cost of Removal asset. This will be corrected in NS Power's 2026 Financial Statements. The reclassification impacted only NS Power's balance sheet, had no impact on NS Power's statement of operations and no impact on NS Power's rate base.

2025 Cost of Removal (COR) Incurred by Capital Item

\$ millions

<u>CI Number</u>	<u>Funding Project Description</u>	<u>COR Incurred</u>
10621-S001-311	TUC - Routine Equipment Replacement	0.0
10645-S001-351	POT - Routine Equipment Replacement	- 0.0
10673-S001-341	TRE - Routine Equipment Replacement	0.1
11500-D004-722	Northeast - New Customer Replacemen	0.3
11505-D007-722	NORTHEAST - JOINT USE AGREEMENT	0.1
11622-H001-405	HYD - Routine Equipment Replacement	0.2
11627-P016-351	POT - Tools and Equipment Routine	0.0
14841-T016-630	PROTECTION MODIFICATIONS AND REPLAC	0.0
14873-D005-756	Sydney Reg. E. - Replace Deteriorat	0.0
14913-D007-735	Joint Use Construction- Coldbrook B	0.0
14960-D006-735	Regulatory Replacements - Coldbrook	0.0
14961-D005-735	Replace Deteriorated Plant - Coldbr	0.1
14982-D004-735	New Customer Replacements - Western	0.3
14983-D005-722	Northeast - Replace Deteriorated Pl	0.2
14984-D006-722	NORTHEAST - REGULATORY REPLACEMENTS	0.0
15021-D007-752	Sydney Region - Joint Use Agreement	0.0
16118-D005-623	Sack. Depot - Replace Det. Plant	0.2
16123-D007-623	Sack. Depot - Joint Use	0.0
16127-D004-623	Sack. Depot - New Cust. Replacement	0.3
16131-D006-623	Sack. Depot - Regulatory Replacemen	0.0
16365-P025-635	MOBILE RADIO ROUTINE	0.0
16374-H517	HYD Gaspereau Dam Safety	- 0.1
16529-D008-735	West - Col Capital Storm Routine	0.0
16538-D008-722	NORTHEAST - STORM ROUTINE	0.0
16550-P028-635	TELECOMMUNICATION SYSTEMS REPLACE A	0.0
16554-D008-623	Sackville Depot Capital Storm Costs	0.0
16661-D008-752	Sydney Storm Routine	0.0
17791-H001-440	STM - HYDRO EQUIPMENT REPLACEMENTS	0.0
18063-D004-752	Sydney Region - New Customer Repla	0.1
18064-D005-752	Sydney Region - Replace Deteriorate	0.2
18065-D006-752	Sydney Region - Regulatory Replacem	0.0
20634-D055-735	Planned D055 For Western Region - 2	0.1
20706-P012-405	HYD - Security Improvement	0.0
20837-D055-623	Sackville Depot - Identified Deter	0.0
20945-P006-863	REPLACEMENT AND ADD'L WORK VEH ROUT	-
20983-D055-752	Sydney Region (D055) - Planned Di	0.1
20986-D055-722	Northeast - Planned Routine Upgrade	0.1
23115-T001-820	PROVINCIAL TRANSMISSION LINE REPLAC	0.5
23118-T011-820	PROVINCIAL - PLANNED TRANS LINE REP	0.3
23120-T003-820	PROVINCIAL-TRANS SUBSTATION PRIMARY	0.1

23121-T004-820	PROVINCIAL- SUBSTATION ADDITIONS &		0.0
23135-D006-800	D006 Regulatory Replacements - Prov		0.1
23136-D007-800	D007 Contractual Replacemens (Joint	-	0.0
23137-D055-800	D055 - Planned Replacement Of Distr	-	0.1
23158-D005-800	D005 Unplanned Replace Deteriorated		0.7
23361-D008-800	D008 Provincial Storm		0.0
26496-D009-571	Meter Routine	-	0.0
26716-D004-800	New Customer Upgrades	-	0.1
27854-S004-311	TUC-ROOFING ROUTINE		0.0
27855-S004-351	POT-ROOFING ROUTINE		0.0
27858-S004-371	POA-ROOFING ROUTINE		0.0
27867-H004-405	HYD-Roofing Routine		0.2
29038-D051-800	System Performance Improvement Rout		0.0
29807-H541	HYD - Tusket Falls Main Dam		0.0
33867-S005-351	POT-Heat Rate Routine		0.0
35583-H005-405	HYD Oil Release Risk Assessment Rou		0.0
35584-H006-405	HYD - Gate Refurbishment Routine		0.0
39305-P062-863	Work Vehicle Replacements	-	
39472-H596	HYD Mersey Redevelopment Phase 1		0.0
39766-D061-800	New Customers - Residential Prov		0.0
39767-D061-623	New Customers - Residential CEN		0.1
39768-D061-752	New Customers - Residential East		0.0
39769-D061-735	New Customers - Residential West		0.1
39770-D062-800	New Customers - Commercial Prov	-	0.0
39771-D062-623	New Customers - Commercial CEN		0.0
39772-D062-735	New Customers - Commercial West		0.0
39773-D062-752	New Customers - Commercial East		0.0
40236-P061-863	Transportation Vehicle Rplcmt Rout	-	
41350-D782	16W-301 Hebron Rebuild Phase 2		0.0
41830-W001-210	Wind - Routine Equipment Replacemen		0.6
42050	CT- TUS Air System Upgrade	-	
44987-T820	L7003 Lidar Upgrades		0.0
45410-D528	IR 270 Barrachois		0.0
45730-D544	Central Planned Deteriorated	-	0.0
45731-D545	East Planned Deteriorated Replace		0.0
45734-D546	West Planned Deteriorated Replace		0.0
45735-D547	Cent Unplanned Deteriorated Replace		0.0
45736-D548	East Unplanned Deteriorated Replace	-	0.0
45737-D549	West Unplanned Deteriorated Replace	-	0.0
45799-D559	Street Light & Service Removals		1.7
46075-P977	IT - Work and Asset Management		0.0
46376-D593	IR 420 and IR 435 Marion Bridge	-	0.0
46483	CT - TUS - Control System Upgrade		0.0
47124-D635	Advanced Meter Infrastructure	-	0.0

47551-H739	HYD - SHH Controls Upgrade		0.0
47671	PTMT - Cathodic protection system		0.0
47794-D745	Heckman Island Underwater Cable Rep	-	0.0
48152-D692	20H-Spryfield Voltage Conversion Ph		0.0
48233-D683	Dist. Inspection Programs	-	0.0
48436-D710	25W-301 Upper Clyde Rd Relocation	-	0.0
48712-H761	HYD - Dam Instrumentation Upgrade		0.0
48913-H765	HYD - Tusket Facility Repairs		0.0
48914-H770	HYD - Malay Falls Facility Refurb		0.0
49546	TRE6 FW Heater Level Control	-	0.1
49555	TRE6 PLC Upgrades WTP		0.0
49756-H791	Marshall Falls Main Dam Refurb		0.0
49775-T927	L5004 Replacements and Upgrades	-	0.0
49779	T-L6537 Replacements and Upgrades	-	0.0
49788	L5564 Replacements and Upgrades	-	0.0
49790-T959	L5505 Replacements and Upgrades	-	0.0
49841-D781	23H-Rockingham Voltage Conversion		0.0
49919-D778	2017 PCB Pole Top Trans. Replacemnt		0.0
49945	HYD - Malay Falls Switchgear Replac	-	0.0
50118-D771	Moose River-Extension		0.0
50518-H792	HYD Ruth Falls Main Dam Refurb		0.2
51234-H822	HYD - WRC HVAC Upgrade		0.0
51235-H823	HYD - WRC Main Access Rd Refurb	-	0.3
51391-D061-722	New Customers - Residential NE		0.1
51392-D062-722	Northeast - New Customers Commercia		0.0
51400	D-2018 Substation Recloser Replacem		0.0
51403	T-2018 PCB Removal Program	-	
51975	5P Mobile Substation Replacement		0.0
52059	L5039 - 2018 Replacements and Upgr	-	0.0
52184	37N-412-Glooscap Trail Rebuild PH2		0.0
52205	30N-412 Hwy 242 Fundy Shore Rebuild	-	0.0
52229	D-16V-314H-New Edinburgh Phase Ext	-	0.0
C0000979	HYD Governor Dam Refurb	-	0.0
C0001900	Mount Hope 69-25kV Substation		0.0
C0002539	HYD Bridge Replacements		0.0
C0002658	Intellirupter Revitalization		0.0
C0004078	D-83V-301 - Gaspereau River Crossin		0.0
C0004138	50W-412GA Port Medway Line Extens		0.1
C0006319	D-2019 PCB Pole Top Transformer Rep		0.0
C0008559	POT - Diesel Generator and Switch		0.0
C0008638	D-Cogswell HRM Redevelopment Progra		0.1
C0008740	Canso Distribution Sys Replacements	-	0.0
C0010019	IT-ADMS Upgrade 2019	-	0.0
C0010335	TRE WWTP Chemical Feed Sys Upgrade		0.0

C0010758	WIN - South Lake Turbine Decomissio		0.0
C0010952	2019/20 Substation PCB Equip Replac		0.0
C0010956	78W-Martins Brook Substation Reloc		0.0
C0011188	D-23H-303 Willet St Underg.Repl		0.0
C0011208	D-2019 Padmount Replacement Program		0.0
C0011209	D-85S-401 Cabot Trail Rebuild	-	0.0
C0011243	T-L5551 -Replacements and Upgrades	-	0.0
C0011321	T-L5031-Replacements and Upgrades		0.0
C0011339	T-L6549-Replacements and Upgr Ph2		0.0
C0011378	Route Network Upgrade		0.0
C0012838	LEQ Canal, Gates and Tailrace		0.1
C0013278	D-102W Tusket Voltage Correction	-	0.0
C0013299	D-102W-312 Tour Des Buttes Way Rebu		0.0
C0013838	HYD WRC LEM Unit Rehabilitation		0.6
C0014019	2019 Substation Recloser Replace		0.0
C0014218	HYD WRC LEM Balance of Plant		0.0
C0015198	50V Kentville Aluminum Light Pole R		0.0
C0015539	D-139H-412- Commissioning New Feede		0.0
C0015545	D-1H, 2H and 104H Inline Switches R	-	0.0
C0015547	Northeast Planned Deteriorated Repl	-	0.0
C0015548	Northeast Unplanned Deteriorated Re		0.0
C0015760	HYD - D4 Riparian Flow Measurement		0.0
C0015761	Cape Breton High Priority FI		0.7
C0015762	Metro High Priority FI		0.2
C0015763	Northeast High Priority FI		0.3
C0015764	West High Priority FI		0.5
C0015779	Deteriorated Make Ready		0.3
C0016183	D-2020 Downline PCB Replacements	-	0.0
C0018160	POA Boiler Refurbishment 2020	-	0.0
C0018319	Cabot Trail Rehabilitation Pleasant		0.0
C0018561	85S-401- Cape Smokey TIR		0.1
C0019025	HYD - Sloane Dam Refurbishment		0.0
C0019579	7N-301 ICP	-	0.0
C0020143	POA CW Valve Actuator Replacement	-	
C0020162	Substation Replacement of Grounds		0.0
C0020313	Customer Care Telephony Platform Up	-	0.0
C0020568	ICP MCC3 Building Refurbishment	-	0.0
C0020628	L6055 - Hwy 107 Monopoles TIR		0.0
C0020834	2020-21 Inaccessible PCB Transf Rep	-	0.4
C0020835	2020 Padmount Replcement Program		0.0
C0020903	CT VJ2 14.5"Bearing Upgrage and Ref		0.0
C0021102	L5029 Replacements and Upgrades	-	0.0
C0021104	L5550 Replacements and Upgrades Ph1	-	0.1
C0021105	L7002 Replacements and Upgrades PH1	-	0.1

C0021106	L7005 Replacements and Upgrades PH1		0.0
C0021122	2020-21 Transmission Switch and Br		0.0
C0021123	2020/2021 Substation PCB Equipment		0.0
C0021182	93V-313G Meteghan Rebuild		0.0
C0021402	TUC Oil Tanks Levels and Pump House		0.0
C0021423	TUC Aux Boiler PLC/DCS Upgrades	-	0.0
C0021607	TUC1 Boiler Flue Gas Containment	-	0.0
C0021643	Sheet Harbour Telecom Upgrades		0.0
C0021943	AMO Weymouth Enhanced Monitoring	-	0.0
C0023802	L6515 Canso Causeway Rebuild		0.0
C0023883	Spring Garden Redevelopment		0.0
C0024162	83V-301 Melanson Road Upgrade		0.0
C0024484	HYD 4th Lake Switchgear MCC Replace	-	0.1
C0024868	Battery Bank and Charger Replacemen		0.0
C0025451	13N-211 Outram & HaveLock Rebuild		0.0
C0025802	93V-313G Meteghan Shore Rd Ph Ext	-	0.0
C0026043	9H-221 Conversion - Jubilee Road		0.0
C0026285	TRE HFO Tank Refurbishment		0.0
C0027362	2020 Petroleum Storage Tank Replace	-	0.0
C0027611	67C-411 - Highway 252 BTR	-	0.0
C0027743	58C-405 Rebuild Margaree		0.0
C0028102	2020 Padmount Switch Replacement	-	0.0
C0028182	4N-311 Targeted Asset Replacements	-	0.0
C0028283	TUC2 South Vacuum Pump Replace		0.0
C0028344	92W-302 Valley Crescent Rebuild		0.0
C0028444	HYD - SHH Crane Refurbishment		0.0
C0028504	Broadband Internet to Rural NS		0.0
C0028564	92H-331 Targeted Asset Replacements		0.0
C0028803	139H-414 Targeted Asset Replacement	-	0.0
C0028804	20H-301 Targeted Asset Replacements	-	0.0
C0028805	HYD - FAR Fish Screen Access Road		0.0
C0028982	104H-411 412 422 423 Targeted Asset		0.0
C0029342	67C-411/58C-403 Mabou and Dunvegan		0.0
C0029682	CT VJ2 - Replace Generator Assembly	-	0.2
C0029690	CT - VJ2 - Control System Upgrade		0.0
C0029695	POA Boiler Refractory Repl 2021	-	0.0
C0029924	LIN BFP Check Valve Replacement	-	0.0
C0030464	100C-421 and 422 Targeted Asset Rep		0.0
C0030486	3S - Targeted Asset Replacements	-	0.0
C0030524	TUC2 Turbine Controls PLC Upgrade		0.0
C0030529	TUC3 Generator Refurbishment		0.0
C0030549	CT - VJ2 - Gen Control and Protect		0.0
C0030702	LIN4 BA Incline Belt Refurbishment		0.0
C0030944	1N-402 1N-405 - Targeted Asset Repl		0.0

C0031044	67N-713 230 kV Breaker Replacem	-	0.0
C0031051	Pennsylvania Breaker Replacements		0.0
C0031053	L5506 Line Replacements and Upgrade	-	0.0
C0031069	L6020 Replacements and Upgrades	-	0.1
C0031085	L6516 Line Replacement and Upgrades	-	0.1
C0031086	TRE TAMS Offsetting 2021		0.0
C0031093	HYD - SHH Inter Protection Panels		0.0
C0031107	55V-314G-Aylesford East Reconductor		0.0
C0031113	61N-204 Townsend Avenue Conversion	-	0.0
C0031117	2H-411-Prospect Rd Phase Extension		0.0
C0031120	76V-301-Maitland Bridge Build to Ro	-	0.0
C0031121	104S-313 - Re-Conductor Big Hill	-	0.0
C0031122	L6539-2021 Replacements and Upgrade	-	0.0
C0031145	2021 Padmount Replacement Program	-	0.0
C0031148	Metro-Stack insulator replacements		0.0
C0031149	Targeted Automatic Sleeve Replaceme		0.0
C0031150	36W-301-Add Third Phase - Allendale		0.0
C0031166	2021 Downline PCB Replacements	-	0.0
C0031188	TRE6 6-5 Feedwater Heater Refurbish	-	0.0
C0031203	2021 Telecom Building Replacemen		0.0
C0031262	2021-22 Transmission Switch & Break		0.0
C0031263	2021/2022 Substation Polychlorinate		0.0
C0031293	11S-411-Coxheath Re-Ins and Recon	-	0.0
C0031296	67C-411GBA Little Mabou Rebuild		0.0
C0031297	709H-221 Bedford 4kV Conversion	-	0.0
C0031300	9H-223 North St Conversion		0.0
C0031302	20V-311-Bluff Rd Rebuild	-	0.0
C0031304	37N-413G-South Athol Rebuild	-	0.0
C0031305	37N-413-HWY 2 Rebuild - Newville		0.0
C0031402	559W-331-Molega Lake Rd Conversion		0.0
C0031403	101W Port Mersey Feeder Exits	-	0.0
C0031482	85S-401 Ingonish Centre BTR		0.0
C0032083	HYD - Mersey Interim Mech Maintenac		0.0
C0032382	Susie Lake Substation Addition		0.0
C0033305	Branch-Line Recloser Additions Pt 1	-	0.0
C0033364	Priority Targeted Device Replace		0.0
C0033384	Targeted Cutout Replacements	-	0.0
C0033405	500 Mic Mac Blvd -Relocation		0.0
C0033429	1H-403 Targeted UG Replacements		0.0
C0033444	63V-312 Stronach Mountain Ph Ext	-	0.0
C0033445	Targeted Pin Insulator Replacements		0.0
C0033507	Underground Switch Replacements		0.0
C0033645	2021-2022 Steel Tower Refurbishment		0.0
C0033666	TUC2 Turbine Turning Gear Refurbish	-	

C0033946	48W-204 Liverpool 4kV Conversion	-	0.0
C0034166	2859 ROBIE STREET RELOCATION	-	0.0
C0034246	POA LS Quarry Reclamation 2021	-	0.8
C0034686	TRE Fuel Tanks Refurbishments	-	0.0
C0034986	Bell - Broadband Internet Phase 2		0.1
C0035506	WIN - Nuttby Collector Circuit Repl		0.0
C0035627	Targeted Inline Switch Replacements		0.0
C0035647	2021 Unplanned Failures (T003)	-	0.0
C0035648	CT - Fuel Oil Piping Code Def.	-	
C0036088	82V-403 Carroll's Corner Bridge		0.0
C0036106	76V-301 Old Harmony Rd Converison	-	0.0
C0036107	82V-403 Highway 277 Pole Replace		0.0
C0036348	LIN4 Steam Drum Lvl Contr Upgr 2022	-	0.0
C0036349	LIN1 RH Tube Replacement 2023	-	0.0
C0036368	HYD - LGB Switchgear Replacement		0.0
C0036408	LIN Wastewater Piping Repl. 2023	-	0.0
C0036526	35C-211 Centennial Road Conversion		0.1
C0036606	30N-411 Maccan River Line Removal		0.0
C0036627	10H-232 Wellington Street Conversio		0.0
C0036628	7N-302G Howard Bridge Rebuild		0.0
C0036646	87W-311,87W-312 Hubbards Highway	-	0.0
C0036668	637N-311 Old Barns Conversion		0.0
C0036669	665H-311 Malay Falls Rd Rebuild		0.0
C0036686	79V-402 Windsor Exit 6 Pole Relocat		0.0
C0036706	96H-411-501H-301 Beaver Harbour Rd		0.1
C0036707	82V-402H - Oakfield Park Rd Relocat	-	0.0
C0036726	4C-441-Monastery Water Crossing		0.0
C0036886	65V-303 Lawrencetown Line Ext	-	0.0
C0037506	Customer Contributed >\$75,000	-	0.3
C0037747	WIN - South Canoe CMS Upgrade	-	0.0
C0037858	2021 Hydraulic Recloser Replacement	-	0.0
C0038629	HYD - Ridge Surge Tank Refurbishmen		0.0
C0038747	LIN1 L-0 Blade Replacement 2023	-	0.0
C0038874	HYD - FAR Spillway Culvert Replacem		0.0
C0039146	LIN3 SCC Refurbishment 2023	-	0.0
C0039166	LIN CW Valve Refurbishment 2022		0.0
C0039346	HYD PE GIS Civil Refurbishment		0.0
C0039446	HYD - Hydro Door Replacements		0.0
C0039506	HYD - MER Hoist PartialRefurbishmen		-
C0039986	2022 113H Feeder Exit Cable Replace	-	0.0
C0040547	129H Kearney Lake Feeder Addition		0.0
C0040826	539W-311 Hemlock Dr Build to Roadsi		0.0
C0040869	POA Boiler Refurbishment 2022		0.0
C0041049	POA Outfall Channel Protection	-	

C0041053	LIN Ladder Swing Gates 2022		0.0
C0041167	79V-402 Falmouth Exit 7 Pole Reloca		0.0
C0041287	73W-412 Bridgewater Hwy Exit Phase2	-	0.0
C0041313	TRE0 Demin Plant Upgrades		0.0
C0041316	TRE0 Floor Plates and Grating 2022	-	0.0
C0041506	CT LM6000 Engine 191-253 Refurbishm	-	0.0
C0041507	CT TUS1 Exhaust Stack Replacement	-	0.0
C0041516	CT TUC 4 Replace Package Hoses	-	0.0
C0041517	CT TUC 5 Replace Package Hoses	-	0.0
C0041522	Fleet - Harden Control System Groun		0.0
C0041526	CT VJ1 Battery Charger	-	0.0
C0041546	AMO Lequille Telecom Upgrade		0.0
C0041647	TUC Dehumidifier Access Improvement	-	0.0
C0041652	TUC Lagoon Pumphouse Upgrade		0.0
C0041655	TUC Steam Drum Level Detection Upgr		0.0
C0041665	TUC2 DCS HMI Upgrade Phase 2	-	0.0
C0041679	TUC6 AVR Replacement		0.0
C0041767	POT-UU Polisher Valves & PLC Upgrad		0.0
C0041786	POT -LFO & HFO System Upgrades 2022		0.0
C0041788	L6516 Replacements and Upgrades Ph2		0.1
C0041789	L5550 Replacements and Upgrades Ph2	-	0.1
C0041790	L8001 Replacements and Upgrades Ph2	-	0.0
C0041793	L7002 Replacements and Upgrades Ph2		0.0
C0041796	L6020 Replacements and Upgrades Ph2	-	0.0
C0041799	TUC Plant Security Upgrades 2022		0.0
C0041800	L5537 Replacements and Upgrades	-	0.0
C0041804	2022 Line Retirement Program		0.0
C0041805	L7005 Replacements and Upgrades Ph2	-	0.0
C0041807	L5534 Replacements and Upgrades	-	0.0
C0041812	L6040 Replacements and Upgrades	-	0.0
C0041816	POT-Next Cell Development-Bear Head		0.0
C0041833	2022 2023 Bulk Oil Breaker Replace		0.0
C0041837	2022 2023 Substation PCB Equip Remo		0.1
C0041946	2022 Automatic Sleeve Replacements	-	0.0
C0041947	2022 Cutout Replacements	-	0.0
C0041954	2022 New Branchline Reclosers		0.0
C0041955	2022 Hydraulic Recloser Replacement		0.0
C0041986	TUC6 HRSG Refurbishments	-	0.0
C0042186	100C-421 - Harvre Boucher Rebuild		0.0
C0042206	L6002 Michelin Line Relocation		0.0
C0042227	CT TUC4 East Nat. Gas Compressor Re	-	
C0042426	11S-411 Coxheath Rebuild Phase 2	-	0.0
C0042586	59C-402 St. Peters Rebuild	-	0.0
C0042606	67C-411GBA West Mabou Harbour Rebui		0.0

C0042626	POA LFO Tank Inspection and Refurb.		0.0
C0042687	15N-202 Arthur St Conversion		0.0
C0042709	67C-411GBA-Colindale BTR	-	0.0
C0042846	15C-211 - Deepdale Conversion		0.2
C0042847	61N-204 High Street Conversion		0.0
C0042886	9H-224 Robie St Conversion		0.0
C0042927	103C-314 - Grand Etang Water Crossi		0.0
C0042933	TRE6 Stack Refurbishment		0.0
C0043110	11S-305 Kenwood Dr Roundabout	-	0.0
C0043130	2022 Padmount Replacement Program	-	0.0
C0043230	65V-301 Nictaux West Reconductor	-	0.0
C0043270	Black River Rd Build to Roadside	-	0.0
C0043330	88W-314-Vancouver St Rebuild		0.0
C0043490	2022 Downline Asset PCB Replacement		0.0
C0043510	2C-402 - Little Judique Reinsulate		0.0
C0043571	2022-2023 Transmission Switch & B		0.0
C0043951	Washmill Lake Drive Line Extension	-	0.0
C0044030	WIN - DIG Hights Brook Crossing Re		0.0
C0044090	2022 Vault Upgrade	-	0.0
C0044172	L7005 Canso Crossing Vibration Miti	-	0.1
C0044590	L5510 Pioneer Coal Line Relocation		0.0
C0044591	Hwy 103 Exit 12 Public Works Line	-	0.1
C0045013	HYD WEY Crane Rail Modification		0.0
C0045353	L5027 Unplanned Repl & Upgr		0.0
C0045510	20V-T52 Transformer Replacement	-	-
C0046370	69V-211 Queen St Reconfiguration	-	0.0
C0046830	HYD - Mersey Jordan Lake Communicat		0.0
C0047294	IT - Microsoft Enterprise Agreement	-	0.1
C0047390	85S-401 - Protection Upgrade		0.0
C0047410	663V-211 - School St 25kV Conversio		0.0
C0047973	HYD ANN Sluice Gates and Check Refu		0.0
C0047990	HYD - Penstock Inspections		0.0
C0048191	ICP UU Temp Area Water Management	-	0.0
C0048750	HYD - SIS Cable & Bushing Replaceme	-	0.0
C0048810	HYD - Mersey Remote Racking Procure	-	0.0
C0048910	705H-211 Mann St Crossing Rebuild		0.0
C0048911	127H-411H Waverly Rd Pole Relocatio	-	0.0
C0048990	HYD AVO 2 Switchgear Replacement		0.0
C0049010	HYD Hells Gate Switchgear Replaceme		0.0
C0049013	HYD - LGB Hoist Replacement		0.0
C0049032	HYD - COF Hoist Replacement		0.0
C0049134	WIN DIG WTG6 Gearbox Replacement		0.0
C0049212	L8001 Replacements and Upgrades Ph3	-	0.0
C0049456	HYD ANN Safety Boom Replacement		0.0

C0049594	TUC3 Aux CW Oil Detection		0.0
C0049895	TUC0 Oil Release Mitigation		0.0
C0050134	LIN Precipitator Refurbishment 2023		0.0
C0050212	HYD Donahue Lake Gate Refurbishment	-	0.0
C0050414	HYD Roseway Asset Decommissioning		0.4
C0050433	LIN1 Boiler Refurbishment 2023	-	0.0
C0050453	LIN4 Boiler Refurbishment 2023		0.0
C0050553	LIN Coal Stacker Refurbishment 2023	-	0.0
C0050554	LIN HFO/LFO Line Refurbishment 2023	-	0.0
C0050556	LIN Guarding and Railing Upgr 2023	-	0.0
C0050636	VT VJ Plenum Door Upgrade		0.0
C0050645	CT VJ Unit 2 Inverter	-	0.0
C0050646	CT VJ Unit 2 Battery Charger Upgrad	-	0.0
C0050648	CT TUC4/5 Air Compressor Upgrade		0.0
C0050654	CT BGT Generator Relief Valve Upgra	-	0.0
C0050656	CT LM6000 Unit 4 New Transmitters	-	
C0050657	CT LM6000 Unit 5 New Transmitters	-	
C0050674	CT BGT Unit 1 Battery Replacement	-	0.0
C0050716	PHB-PE Guarding Rotating Equipment	-	0.0
C0050766	TRE - 4kV Breaker Replacements 2023		0.0
C0050775	TRE - Ash Site Management 2023		0.0
C0050801	TRE6 - Boiler Refurbishment 2023		0.0
C0050805	TRE6 - Mills Refurbishment 2023		0.0
C0050811	TRE6 - Waterwall Panel Replacement	-	0.0
C0050823	TRE6 - Main Turbine Valve Refurb.		0.0
C0050827	TRE6 - Misc. Valve Refurb. 2023	-	0.0
C0050833	TRE6 - Boiler Safety Valves Refurb		0.0
C0050835	2023/2024 Steel Tower Refurbishment		0.0
C0050836	2023 Padmount Replacement Program		0.0
C0050840	TUC - Lighting Program 2023		0.0
C0050842	2024 Bulk Oil Breaker Replacement		0.0
C0050894	TUC - Plant Security Upgrades 2023	-	0.0
C0050895	TUC Platform & Ladder Upgrades 2023		0.0
C0050906	TUC - Sensors & Alarms Refurb 2023	-	0.0
C0050908	TUC - Stoplog Replacement		0.0
C0050912	TUC - AC / Chiller Unit		0.0
C0050913	TUC - SEL Motor Port Relays Replace	-	0.0
C0050914	TUC East Gas Compressor Motor Refur		0.0
C0050915	TUC - Obsolete Instruments Replacem	-	0.0
C0050917	TUC - Electrical Panel Replacements		0.0
C0050922	TUC2 - DCS/Graphics		0.0
C0050952	LIN4 Water Wall Replacement 2023	-	0.0
C0051013	LIN1 Burner Front Replacement 2023		0.0
C0051032	TUC1 Natural Gas Valves Refurb 2023	-	0.0

C0051033	TUC1 - Boiler Refurbishment 2023		0.0
C0051073	TUC1 - Turbine Valves Refurbishment	-	0.0
C0051076	PTMT-P&A Inhaul Conveyor Idler Asse	-	0.0
C0051078	TUC1 - Electric Actuators 2023		0.0
C0051079	TUC1 - Motor Refurbishments 2023		0.0
C0051092	CT BGT Bleed Valve Upgrade 2023		0.0
C0051112	PHB-Boiler Refurbishment 2023		0.0
C0051132	PHB-Trancel Screw Refurbishment2023	-	0.0
C0051134	TUC2 L-0 Blade Replacement	-	0.0
C0051135	TUC2 - Turbine Valves Refurb 2023	-	0.0
C0051139	TUC2 - South CW Pump Refurb 2023		0.0
C0051140	PHB-Conveyors &Handling Systems2023	-	0.0
C0051142	TUC2 - Electric Actuators 2023		0.0
C0051143	TUC2 - Motor Refurbishments 2023	-	0.0
C0051144	TUC2 - MCC Refurbishments 2023	-	0.0
C0051153	TUC3 - Electric Actuators 2023		0.0
C0051154	TUC3 - Motor Refurbishments 2023		0.0
C0051158	TUC3 S CW Pump & Motor Refurb 2023	-	0.0
C0051161	PHB-Ash Chutes Silo Refurbishment	-	0.0
C0051162	PHB-Woodward Controller Upgrade2023		0.0
C0051172	TUC3 - CW Pump Discharge Exp Joint	-	0.0
C0051173	TUC3 - West CEP Pump & Motor	-	0.0
C0051175	TUC3 - Meshing Gear Upgrade		0.0
C0051181	TUC3 - Gen Sync Upgrade Project	-	0.0
C0051183	TUC3 - DCS/HMI Upgrade 2023	-	0.0
C0051189	TUC6 - Breaker Refurbishments 2023		0.0
C0051190	TUC6 - Electric Actuators 2023		0.0
C0051191	TUC6 - 4160V/600V Motors 2023	-	0.0
C0051339	PHB-DCS Electrical Upgrade Phase 1		0.0
C0051355	PHB - Lighting Upgrades 2023		0.0
C0051393	TUC1 Condenser Sump Struct Refurb		0.0
C0051413	PTMT-Main Feed Belt Refurbishment		0.0
C0051432	POT - Asbestos Abatement 2023		0.0
C0051452	POT - Boiler Refurbishment 2023	-	0.0
C0051454	POT - Breaker Replacements / Upgrad	-	0.0
C0051456	POT - Guards, Railings, and Swing G		0.0
C0051457	POT - Facility Upgrades 2023		0.0
C0051458	POT - Lighting Upgrades 2023	-	0.0
C0051472	POT - #2 West Condensate Pump & Mot		0.0
C0051473	POT - Fire Detection Upgrades 2023		0.0
C0051477	POT - DCS Server Upgrades 2023		0.0
C0051478	POT - Lube Oil System Refurbishment		0.0
C0051480	POT - Sternson Carbon filter replac	-	0.0
C0051485	POT - Water Treatment Plant Sprinkl	-	0.0

C0051514	POT-Hot Release Vent line Refurbish	-	0.0
C0051592	LIN BFP Recirc Line Replace 2023	-	0.0
C0051712	TUC1 WTP Train Refurb		0.0
C0051735	11S-411GA Eskasoni Protection Upgra	-	0.0
C0051873	12V-302H - Mills Brook Reconductor	-	0.0
C0051892	LIN1 Gen. Bus Coupler Refurb 2023		0.0
C0051894	TUC - HFO Tank No.3 Refurbishment	-	0.0
C0051933	HYD - WEY Tailrace Pump Replacement	-	0.0
C0052057	CT TUS Unit Transformer Replacement	-	0.0
C0052073	100C-422 Pirate Harbour Rebuild		0.0
C0052113	ICP PE Main Storage Area Water Mgmt	-	0.0
C0052155	TRE6- Attemperator block&cntr valve	-	0.0
C0052274	POA Boiler Refractory Repl. 2023		0.0
C0052276	POA Expansion Joint Repl. 2023		0.0
C0052294	POA Boiler Refurbishment 2023		0.0
C0052296	POA 4KV 600V Breaker Refurb. 2023		0.0
C0052302	POA SH1 Refurbishment 2023	-	0.0
C0052454	POA Analytical Panels Upgrade 2023		0.0
C0052458	POA Boilerhouse Ventilation Upgrade	-	0.0
C0052514	HYD MacDonald Dam Access Improvemen		0.0
C0052634	L5016 Replacements and Upgrades		0.0
C0052798	10C-211 Fleur-de-Lis Trail Conversi		0.0
C0052818	10C-212 Arichat Conversion		0.0
C0052854	70W-321H Dauphinee Rd BTR		0.0
C0052874	HYD MAL Plant Electrical Upgrades	-	0.0
C0052894	2023 Vault Upgrade		0.0
C0052935	TUC5 Winterization 2022	-	
C0052955	TUC6 Winterization 2022		0.0
C0053014	89W-303 Station Rd Line Extension	-	0.0
C0053035	16W-301H Pembroke Rd Rebuild		0.0
C0053054	626N-T1 Little Dyke Rd Stepdown Upg	-	0.0
C0053074	TRE - Asbestos Abatement 2023	-	0.2
C0053114	BGT Fuel Piping/Cable Bridge 2023	-	0.0
C0053174	73W-411GCA Gilberts Lane BTR	-	0.0
C0053294	2023 127H Feeder Exit Cable Replace	-	0.0
C0053295	L5004 Kearney Lake Rebuild		0.1
C0053314	POT- LFO&HFO System Refurbishment	-	0.0
C0053335	TUC2 Ash Handling Upgrades		0.0
C0053414	TRE5 U&U HEP/FAC 2022		0.0
C0053514	100C-421 Aulds Cove Relocation		0.0
C0053517	9H-221 University Ave and Morris St		0.0
C0053655	HYD - COW 11 Overhaul		0.0
C0053656	HYD COW 11 Generator Refurbishment	-	0.0
C0053718	HYD - Dam Safety Routine		0.1

C0053975	Sept 23, 2022 Level 4 Storm Fiona	-	0.4
C0054015	Distribution Protection Upgrades Pa	-	0.0
C0054077	HYD TUS Winch Replacement		0.0
C0054115	HYD TUS Carleton Fish Ladder Upgrad	-	0.0
C0054356	TUC Roof Replacement 2022 U&U		-
C0054416	TUC2 FAC Refurb 2022		0.0
C0054535	POA UU Crossover Refractory Repl.	-	0.0
C0054556	POA UU SH3 Tube Replacements	-	0.0
C0054638	VJ2 MCC Upgrade 2022	-	0.0
C0054818	1N-421 - Fundy Discovery Site		0.0
C0054835	TUC Hydrogen Trench Refurb 2023	-	0.0
C0054975	TRE6 U&U 6-5 Feedwater Heater Refur	-	0.0
C0055155	TUC Stack Platform Replacement		0.0
C0055378	TUC1 FAC Refurb 2022	-	0.0
C0055415	101H-421-Hwy 107 Connector Pole Rel		0.0
C0055475	78W-301 Second Peninsula Phase Addi	-	0.0
C0055616	Telemetry Equipment Installation	-	0.0
C0055696	L5031 Replacement & Upgrade R.C Tap		0.1
C0055796	2023 EHV Breaker Replacements		0.1
C0056020	4N-313 Kavanaugh Mills Bridge Repla	-	0.0
C0056240	2024-2025 Transmission Switch & Bre		0.0
C0056241	82V-402 Wellington Roundabout Pole	-	0.0
C0056342	16N-301 2878 Hwy 2 Shubenacadie Riv		0.1
C0056402	4S-332 - Charlotte St. Re-design Ph	-	0.1
C0056681	WIN - NUT 2023 Ice Storm Refurbishm	-	0.0
C0056842	July 22, 2023 Level 3 Storm - Dist	-	0.0
C0057001	TRE6 U&U Tripper Conv. Skirting Rpl	-	0.0
C0057422	TRE U&U Fire water valves repl		0.0
C0057682	6N-T51 Transformer Replacement		0.0
C0057882	2024 Pennsylvania Breaker Replace		0.0
C0057901	101H-423 Bedford Exit 4 Rebuild		0.0
C0057925	82V-403 Hydes Bridge Pole Relocatio	-	0.0
C0057962	LIN UU CW Platform Refurb 2023		0.0
C0057982	TUC3 HEP Refurb 2023		0.0
C0058002	TRE5 Boiler Refurbishment		0.0
C0058022	TRE5 U&U Precip Refurbishment		0.0
C0058023	TRE5 PE Air Heater Refurbishment		0.0
C0058024	TRE5 Misc Valves Refurbishment 2023		0.0
C0058025	TRE5 CW Pump Refurbishment	-	0.0
C0058103	2023 Merlin Gerin Breaker Replaceme	-	0.0
C0058162	TUC3 Condenser Refurb 2023 PE		0.0
C0058165	131H-422 Old Mines Rd Phase Extensi		0.0
C0058166	TUC Railway Culvert Refurb	-	0.0
C0058224	TUC2 Pedestal 6 Leak Refurb		0.0

C0058325	HYD COW11 Governor Mount Replacemen	-	0.0
C0058522	TRE5 U&U Deaerator Level Xmitter Rfb	-	0.0
C0058662	TRE6 PE Precip Refurbishment	-	0.2
C0058682	TRE5 Coal Mill Bunkerette Refurbish		0.0
C0058683	TRE5 Gland Steam Control Valves Rfb	-	0.0
C0058684	TRE5 Draft Plant Refurbishment 2023		0.0
C0058686	TRE5 5-1 CW pump isolation Valve	-	0.0
C0058931	TRE5 U&U 5-2 Mill Refurbishment	-	0.0
C0058945	TUC3 Boiler Refurb 2023 U&U	-	0.0
C0058983	50N-410 Hwy 104 Twin - Lamont Rd Cr	-	0.0
C0058984	50N-410 Hwy 104 Twinning - Site 8A		0.0
C0059023	POA UU Feedwater Valves Refurb.		0.0
C0059046	101S and 79N Reactor Replacements	-	0.0
C0059102	HYD LGB Hoist Boom Refurbishment		0.0
C0059162	POA UU Acid Day Tank Repl.		0.0
C0059165	79V-403 College Road Pole Relocatio		0.0
C0059283	LIN2 PE 2023/2024 Winter Cap Req	-	0.0
C0059386	TRE6- 6A&B CWPump discharge Mot val		0.0
C0059403	62H Low Voltage Switchgear Replacem	-	0.0
C0059443	LIN1 UU Turbine Bearing Replac 2023	-	0.0
C0059465	PHB - UU PB3 Lower Furnace Tube Lea	-	0.0
C0059482	LIN1 UU Boiler Tube Refurb 2023	-	0.0
C0059510	TUC WWTP Refurb	-	0.0
C0059518	88H-402J Rutherford Bridge Relocati		0.0
C0059623	POA UU DCMS Server Upgrades		0.0
C0059625	TUC3 Misc Valves Refurb 2023		0.0
C0059671	TUC Rigging Management Upgrades		0.0
C0059868	TUC HFO TSV Tank	-	0.0
C0059962	TUC1 Boiler Tube Replacement 2023		0.0
C0060224	PHB UU Superheater Safety Valve R	-	0.0
C0060304	PHB-UU HEP Inspection & Repairs 202	-	0.0
C0060323	PTMT Rainwater System U&U	-	0.0
C0060384	TUC Wharf Upgrades 2023		0.0
C0060385	TUC6 Crit Equip Access Refurb	-	0.0
C0060443	HYD Paradise Generator Refurb		0.0
C0060523	11S-301 Campbell Road Water Crossin		0.0
C0060626	LIN1 UU SCC Structural Refurbish	-	0.0
C0060684	HYD Mersey Hoist Refurbishment COW/		0.0
C0060685	LIN4 UU Misc. Valve Refurb 2023	-	0.0
C0060706	LIN UU Sootblower Refurbishment	-	0.0
C0060811	TUC1 Boiler Tube LeakReplace 2 2023		0.0
C0061290	POT-UU Valve Component Refurbishmen		0.0
C0061291	POT- UU Boiler Tube Leak 2023		0.0
C0061292	POT-UU Gland Steam Refurbishment	-	0.0

C0061293	POT-UU CW Motor's Refurbishment 202		0.0
C0061294	POT-UU Coal Mill Refurbishment		0.0
C0061328	TUC1 CW Discharge Pipe Refurb	-	0.0
C0061484	PTMT E-Crane Stabilization		0.0
C0061705	POA SD UU LS Rotor Replacement		0.0
C0061927	Sept 16 2023 - Hurricane Lee Distri	-	
C0061930	Sept 16 2023 - Hurricane Lee Transm	-	0.0
C0061931	Sept 16 2023 - Hurricane Lee Substa		0.0
C0062083	LIN UU Elevator Refurbishment		0.0
C0062303	POA UU SH3 Refurbishment		0.0
C0062304	POA UU Coal Bidirectional Repl.		0.0
C0062305	POA UU HEP 2023		0.0
C0062443	Dec 11, 2023 Level 3 Storm - Distri		0.0
C0062447	Dec 11, 2023 Level 3 Storm - Substa	-	0.0
C0062603	LIN UU 4D Mill Refurbishment	-	0.0
C0062665	POT-UU HEP Inspection & Repairs 202	-	0.0
C0062724	LIN4 UU Bottom Ash Refurbishment	-	0.0
C0062727	LIN UU Seal Water Pump Replacement	-	0.0
C0062824	POT-UU Turbine Oil System Refurbish		0.0
C0062924	TUC1 Condenser Refurb 2023	-	0.0
C0063043	TUC WTP Tank3 Cation Vessel Refurb	-	0.0
C0063063	TUC2 Seal Oil Cooler Backwash	-	0.0
C0063145	CT LM191-332 3-5 Bushing Replace	-	0.0
C0063183	TUC2 CWIntake Discharge Pipe Refurb		0.0
C0063185	POA WW Discharge Relocation		0.0
C0063264	L5573 Replacements and Upgrades	-	0.0
C0063268	L5058 Replacements and Upgrades	-	0.0
C0063270	L8002 Replacements and Upgrades		0.0
C0063272	L5546 Replacements and Upgrades		0.0
C0063273	L6024 Replacements and Upgrades	-	0.0
C0063274	L7008 Replacements and Upgrades	-	0.0
C0063275	L5033 Replacements and Upgrades	-	0.0
C0063283	TUC2 Lube Oil Tank Refurb	-	0.0
C0063303	TUC2 HEP Refurb 2023		0.0
C0063383	TUC2 SDIR Findings Refurb/Replaceme	-	0.0
C0063384	L5535 Replacements and Upgrades	-	0.0
C0063463	POT-UU Demin Pump Refurbishment	-	0.0
C0063524	PHB - UU Precip Ash Collection Refu		0.0
C0063784	POT-SD UU Boiler Tube Leak Dec 2023	-	0.0
C0063823	LIN1 UU B BFP Recirc Valve Replace	-	0.0
C0063829	LIN3 UU A BFP Nozzle Refurbishment		0.0
C0063903	LIN4 UU Boiler Tube Refurb 2023	-	0.0
C0063904	LIN3 UU Misc. Valve Refurb 2023	-	0.0
C0064123	Dec 18, 2023 Level 3 Storm Distrib		0.0

C0064126	Dec 18, 2023 Level 3 Storm Transmis	-	0.0
C0064349	LIN UU 4A Mill Refurbishment	-	0.0
CONV-T003-800	T003-TRANSMISSION SUBSTATION REPLAC		0.0
C0035666	EV Charging Stations 2021	-	
C0030263	L7003 & L7004 - Hwy 104 Twinning		0.0
C0031224	58C-405HA Middle River Reconfig		0.0
C0021109	2020 RTU Deployment Project	-	0.0
C0031170	87W-312G-Blandford-Little Tancook S	-	
C0036649	665V-311 Locks Rd Conversion		0.0
C0033426	Underground Manhole Water Pumps	-	
C0041319	TRE PAC system upgrades 2022		0.0
C0031169	IT-GIS Upgrade & Field Map Mig 2022	-	0.0
C0029803	POA Access Improvement 2021	-	0.0
C0030204	LIN WTP Chemical Pump Skid Repl		0.0
C0021283	AMO T&D Telecom Upgrades	-	
51398	2018/2019 Steel Tower Refurb		0.0
C0021982	ICP UU Unloading Hopper Replacement		0.0
C0030482	LIN Wastewater System Instrum.		0.0
C0010778	Smart Grid Nova Scotia Project	-	
C0036046	48H-301 Sinclair St Pole Replace		0.0
C0025447	113H-441G Colby Drive Rebuild		0.0
C0022662	22C-404GA Lennox Passage Rebuild	-	0.1
C0020842	POT - Turbine Generator Fire Protec	-	
16145-P002-623	SACK. DEPOT - TOOLS & EQUIPMENT	-	
C0031022	IT- Identity & Access Management		0.0
C0021839	IT-Customer Energy Management	-	0.0
C0030824	POA Heat Tracing Upgrades		0.0
C0022744	2020 Oil Containment Program	-	
C0026683	T&D Reliability Enhancements		0.0
C0035527	Kings Road Roundabout Phase 2		0.0
C0036009	20H-303 Essex Dr Framing Replace		0.0
C0038626	HYD - WRC U1 Control Panel	-	0.0
C0028123	LIN UU Dry Ash Unloading Refurb.	-	
C0039006	4N-311 Targeted Device Replacements		0.0
C0030550	CT - VJ1 Gen Control and Protection	-	
C0031052	Replenish Spare used at 58C	-	0.0
C0039571	Transmission Plan Stability & EMT	-	
C0032664	ECC Optimization Tools Project	-	0.0
C0040186	PE TRE PCB Equipment Replacement		0.0
C0015681	D-87H-311-East Chezzetcook Rd- 3-Ph		0.0
C0020082	POA Service Air Compressor	-	0.0
C0038569	DSR Mersey Deep Brook Development	-	
14949-P002-863	ADMIN SERVICES - TOOLS & EQUIPMENT	-	
C0029242	1N-421 Tidal Bore Rd Line Extension	-	0.0

C0036667	618V-311 Mill Rd Conversion		0.0
C0053018	TRE6 Upper Waterwall Panels Replac		0.0
C0059530	TRE0 U&U Plant Heating Refurbishmen	-	0.0
C0030522	TUC2 TWIP PLC Upgrade	-	0.0
C0054155	Hell's Gate Dam Refurbishment	-	0.0
C0023623	AMO Distribution APM Program		0.0
C0060551	TUC HVAC Refurb 2024		0.0
C0052299	2023 2024 Steel Tower Life Extensio	-	
C0052674	Customer Driven Projects > \$75K		0.2
C0059483	83V L5017 and L5046 Rebuild Tap	-	0.0
C0043390	664N-211 Claremont Ave Conversion		0.0
C0039386	HYD - Bloody Creek Safety Improveme		0.0
C0055539	10H-T1 Transformer Replacement	-	0.0
C0055557	76V-T1 Transformer Replacement		0.0
C0041953	2022 Recloser Remote Connectivity	-	0.0
C0056041	4N-311 Wallace River Bridge Rebuild	-	0.0
C0053699	Renewable to Retail Implementation	-	0.0
C0025458	126H-312G-Murphy Rd Rebuild		0.0
C0043550	IT - AMI Head-End System Upgrade	-	
C0053116	28N-201 Little Forks Road Upgrade		0.0
C0041893	2022/2023 Trans ROW Widening 69kV	-	
C0041791	L6551 Replacements and Upgrades		0.3
C0039266	HYD - Gulch Overhaul		0.1
C0057763	IT - Automated Vulnerability Respon		0.0
C0036670	33N-201 Canaan Rd Conversion		0.0
49659	TUC Oil Pumphouse PLC Upgrade		0.0
C0052914	ICP Rail Center Fuel System Refurb.	-	0.0
C0051136	TUC2 - HP/IP Turbine Refurb 2024		0.0
C0051141	TUC2 Condenser Waterbox Refurb 2023		0.0
C0056722	2023 Distribution Inspection Progra		0.0
C0059524	15N-401 15N-402 McClures Mills Rd		0.0
C0060751	2024 Manhole Automatic Pumps	-	0.0
C0060752	2024 Feeder Exit Replacements	-	0.0
C0062524	Damage Assessment Enhancements 5.0		0.0
C0066669	TUC WTP Tank 3 Cation Nozzle Refurb	-	0.0
C0060781	POT – Fuel Delivery Control & Instr		0.0
C0067048	58C-405HA Upper Middle River Bridge		0.0
C0067103	POA UU North Lpsl Refractory Repl.	-	0.2
C0063965	TRE6 UU Coal Feed Pipe Enhancement		0.0
C0062063	HYD - Dam Generator Procurement	-	0.0
C0063803	HYD AVO 2 Access Road Stabilization	-	0.0
C0061360	TRE6 - Conveyors Refurbishment 2024	-	0.0
C0061525	ECC Facility Ratings	-	0.0
C0039666	LIN34 Control Room Refurb 2024	-	0.0

C0060544	LIN Mill Refurbishment 2024	-	0.1
C0062486	TUC3 Electric Actuators 2024		0.0
C0060595	TUC6 Electric Actuators 2024		0.0
C0060759	55V-314H-Aylesford Road Phase Exten		0.0
C0067104	POA UU B RA Fan Refurb	-	0.0
C0061376	TRE5 - 5-2 CW Pump Refurbishment		0.0
C0067117	TUC3 Electrostatic Precip Refurb	-	0.0
C0067123	TUC1 South BFP & Motor Refurb 2024	-	0.1
C0067023	LIN2 PE 2024/25 Capacity Req	-	0.2
C0067166	POT - PE FAC 2024	-	0.1
C0041324	TRE6 6B Pinnion and Bullgear Refrb		0.0
C0060765	POT - Facility Upgrades 2024		0.0
C0067204	POT-UU Unit 2 Roofing Repairs	-	0.0
C0067183	TUC Wharf Access Bridge Replacement	-	0.1
C0061384	512W-311-Lake Torment Loading Issue		0.2
C0060756	113H-433G-Route 207 Phase Extension		0.0
C0060605	TUC3 Boiler Refurb 2024		0.0
C0066743	POT - SD UU Package Boiler	-	0.0
C0061524	TRE5 - 5-4 Mill Refurbishment		0.0
C0067067	TRE5 U&U U5 Governor Refurbishment	-	0.0
C0067086	TRE6 U&U 6A CW Pump Refurbishment	-	0.1
C0067303	4C-430H Salt Springs Rd Failure Rep		0.0
C0067444	HYD COW Stop Log Replacements	-	0.1
C0053657	HYD COW Filler Gate Replacements	-	0.2
C0060598	TUC6 HRSG Boiler Refurb 2024		0.0
C0067286	LIN3 UU SH3 Header Refurb 2024	-	0.0
C0061300	TRE - Asbestos Abatement 2024		0.0
C0067214	PHB-UU PB3 Wall Repairs	-	0.0
C0067167	TRE5 UU U5 Boiler Safety Valves	-	0.0
C0060582	TUC2 Polisher Inlet/Outlet Valve		0.0
C0052595	POA Burner Front Valve Trains	-	0.0
C0060964	POA Fire System Upgrades 2024	-	0.0
C0067424	TRE5 U&U 5-2 FD Fan Motor	-	0.0
C0067448	TRE0 U&U Coal Slicer	-	0.0
C0067243	TRE5 U&U Burner Front	-	0.0
C0031125	TRE5 Boiler Refurbishment 2024		0.1
C0030783	POA Generator Refurbishment		0.0
C0060707	BGT1 Generator Refurbishment		0.0
C0060812	POT-WTP MCC Upgrade		0.1
C0061385	5N-301-Debert Stepdown Replacement	-	0.0
C0061266	19C-204 - Durells Island Conversion		0.1
C0067285	LIN PE Runoff Water Assessment 2024	-	0.0
C0060584	TUC2 Air Heater Refurb 2024	-	0.0
C0060594	TUC6 Turbine Valves Refurb 2024	-	0.0

C0067704	ICP #2 Stacker Drive U&U		0.0
C0067686	Lumsden Rubber Dam Replacement	-	0.0
C0021342	HYD Lumsden Intake & Butterfly Valv	-	0.0
C0067723	RC Lingan Crossings Refurb	-	0.0
C0067725	ANN Sidewalk Access Cover Refurbish	-	0.0
C0064783	WIN DIG Yaw Drive Replacements	-	0.0
C0067747	ANN Tidal - MCC Replacement		0.0
C0064726	2024 Padmount Switch Replacement		0.0
C0060806	POT - Graver Carbon Filter Replacem		0.0
C0060780	POT - #2 West Extraction Pump Refur		0.0
C0060743	PHB - New Skid Steer	-	0.1
C0061103	642V-311-South Rawdon Rd Conversion		0.1
C0009316	POA Coal Gallery Struc. Refurb.		0.1
C0061703	L5028 LaFarge Transmission Tap Rebu	-	0.0
C0061046	2024 Merlin Gerin Breaker Replaceme	-	0.0
C0060592	TUC3 Analysical Panel Modifications		0.0
C0060787	POT - Turbine Valves Refurbishment		0.8
C0064729	TRE5 U&U WW Tube Replacement	-	0.0
C0061903	96H-411- Tangier Bridge Relocation		0.0
C0062028	CBHNP North Mountain Building Repla	-	0.0
C0064723	26N-211 Joggens Stepdown Retirement		0.0
C0064843	113H-433G West Lawrencetown Stepdow		0.0
C0064903	IR 664 - 99W Bridgewater BESS TPIF	-	0.1
C0062144	Rural Nova Scotia EV Fast Charging	-	0.2
C0052615	ICP Locomotive Governor Refurb U&U		-
C0061185	TUC1 Boiler PSV Refurb	-	0.0
C0060705	LIN1 Misc. Valve Refurbishment 2024	-	0.0
C0061265	LIN4 Turbine Valve Refurb 2024	-	0.1
C0060599	TUC Lighting Program 2024		0.0
C0065125	TUC3 FAC Refurb 2024	-	0.1
C0065143	ICP Unload Hydraulics Bldg U&U	-	0.0
C0061526	TRE5 - 5x Pulverizer Refurbishment		0.0
C0060558	TUC Rotating Equipment Guards 2024	-	0.0
C0060816	POT - HFO Tank Refurbishment		0.6
C0060557	TUC Station Fuel Oil Upgrades		0.0
C0061847	BGT Tank 2 Refurb		0.0
C0060256	POA LS Quarry Reclamation 2024	-	0.5
C0060735	PHB-Conveyors & Handling Systems 24	-	0.0
C0060807	POT - Overhead Door Replacement		0.0
C0065343	TUC HFO Piping Refurbishments 2024	-	0.0
C0065303	TRE6 UU 6A ID Fan Motor Refurb	-	0.0
C0049974	HYD - Gulch Crane Upgrades		0.0
C0060723	LIN4 Misc. Valve Refurbishment 2024	-	0.0
C0061543	L5048 Replacements and Upgrades	-	0.0

C0060608	TUC6 Turbine Refurbishment 2024		0.0
C0060609	TUC3 STG Steel Column Fire Protecti		0.0
C0060570	TUC1 AVR Replacement		0.1
C0061529	L6001 Replacements and Upgrades		0.0
C0064923	PHB - SD UU Precipitator Collecting	-	0.0
C0060727	PHB - Air Heater Refurbishment 2024	-	0.0
C0063546	RC New Waterford Railbed Refurb		0.0
C0063548	ICP Lighting Upgrades 2024		0.0
C0060724	PHB - Boiler Refurbishment 2024		0.0
C0063550	ICP Conveyor Take-Up Refurb		0.0
C0063552	ICP Pier Hydraulics & Elec Refurb	-	0.0
C0063555	ICP Chute Replacment		0.0
C0063557	ICP Wind Fence Paneling		0.0
C0065514	HYD MAL Instrumentation Cable Repla	-	0.0
C0061504	ICP Rail Car & Truck Refurb 2024		0.0
C0051392	ICP Pier Subsurface Inspection		0.0
C0060691	LIN4 Boiler Refurbishment 2024	-	0.1
C0064868	IT - Vul. Remediation for IT & OT	-	0.0
C0060690	LIN3 Boiler Refurbishment 2024	-	0.1
C0061403	2024 2025 Sacrificial Anode Install	-	0.1
C0061267	LIN D1 Conveyor Belt Replace 2024	-	0.0
C0063323	L6527 Fiber Replacement		0.0
C0061365	TRE6 - 6F Belt Replacement		0.0
C0038126	HYD - COW 12 Overhaul		0.1
C0059783	HYD ULF 2 Overhaul		0.0
C0051156	TUC3 - MCC Refurbishments 2023		0.0
C0051080	TUC1 - MCC Refurbishments		0.0
C0050916	TUC - DCS / HMI Network 2023	-	0.0
C0062463	Tools for Additional Line Crews		-
C0061904	20N-203 Queen St Rebuild		0.0
C0051192	TUC6 - MCC Refurbishment 2023		0.0
C0060245	HYD Mersey PH Concrete Assessments		0.0
C0060569	HYD LGB Roof Replacement		0.1
C0064563	HYD DIB Field Breaker Panels	-	0.0
C0065244	HYD MIL 2 U/G Bearing Replacement	-	0.0
C0053654	HYD COW 12 Generator Refurbishment		0.2
C0059785	HYD BIF 6 Exciter Refurbishment		0.0
C0060712	LIN3 Misc. Valve Refurbishment 2024	-	0.0
C0060766	LIN4 Burner Front Replacement 2024	-	0.0
C0050472	LIN3 Boiler Eros Reduc Refurb	-	0.1
C0061327	LIN Fly Ash Hopper Vibrator Replace	-	0.0
C0060763	LIN3 Burner Front Replacement 2024	-	0.0
C0061375	TRE - Sootblowers 2024		0.0
C0060562	TUC1 Boiler Refurb 2024		0.0

C0060596	TUC6 4160V/600V Motors 2024		0.0
C0060566	TUC1 Natural Gas Refurb 2024		0.0
C0060577	TUC2 Boiler Refurb 2022		0.0
C0060581	TUC2 Natural Gas Valves Refurb 2024		0.0
C0060774	POT - Breaker Replacements / Upgrad		0.0
C0060770	POT-Valve Replacement 2024	-	0.0
C0060767	POT- Asbestos Abatement 2024	-	0.0
C0051495	POT - Bulk Caustic Transfer Pump Re	-	0.0
C0060248	POA Ash System Refurb. 2024	-	0.0
C0060255	POA Plant Lighting Upgrade 2024		0.0
C0060251	POA Access Improvement 2024	-	
C0060268	POA Ion Chromatography Equip. Repl.		0.0
C0060555	TUC Sensors & Alarms 2024		0.0
C0060764	POT - Lighting Upgrades		0.0
C0061225	POA Rotometer Replacement	-	0.0
C0060783	POT - HVAC Refurbishment 2024	-	0.0
C0065294	L5561 Reroute - CBU Expansion	-	0.0
C0066283	RC to Lingan Sinkhole Repair U&U	-	0.0
C0060786	POT - West CW Pump Refurbishment	-	0.0
C0065787	LIN Wash Water Pump Installation	-	0.0
C0065804	TUC3 Boiler Tube Leak FEB24	-	0.0
C0065823	TUC1 HP Gov Valve Replace 2024	-	0.0
C0066343	85S-401GA Halfway Brook Road Realig		0.0
C0060606	TUC3 Natural Gas Valves Refurb 2024		0.0
C0060552	TUC Condensate Recovery		0.0
C0060601	TUC WTP Piping Replacement 2024		0.0
C0060249	POA Valve Component Repl. 2024		0.0
C0052435	POA Facilities Security Upgrades		0.0
C0052438	POA BA Center Drain Valve Rep. 2024	-	0.0
C0058902	Substation Engineering Standards Up		0.0
C0060244	POA Boiler Refractory Repl. 2024		0.0
C0060246	POA Boiler Arrowhead Repl. 2024	-	0.0
C0060247	POA Expansion Joint Repl. 2024		0.0
C0060250	POA Boiler Refurb. 2024		1.0
C0060252	POA 4KV 600V Breaker Refurb. 2024		0.0
C0060261	POA CW Pump Refurb.		0.6
C0063953	TUC3 Bearing 8 Replacement	-	0.0
C0052459	POA Overhead Door Replacements		0.0
C0063964	TUC2 Boiler Attenuator Replace		0.0
C0060733	PHB-Trancel Screw Refurbishment 202	-	0.0
C0060778	POT - Boiler Refurbishment 2024	-	0.0
C0065926	POT - PE SOFA Duct Attachment	-	0.0
C0060722	PHB-Precipitator Refurbishment 2024		0.0
C0051815	RTU Replacements Program Phase 6		0.0

C0061362	TRE5 - 5D Belt Replacement		0.0
C0066643	TRE UU AAMS Runoff Pond Refurb.	-	0.0
C0060771	POT - Coal Mill Refurbishment 2024		0.1
C0060777	POT - Fire Detection Upgrades 2024		0.0
C0061003	POA LP HIP Turbine Refurb		1.5
C0061372	TRE - WTP No.6 Resin Replacements	-	0.0
C0051052	LIN Coal Reclaim PLC Upgrade 2024	-	0.0
C0060587	TUC3 Misc Valve Replacement 2024		0.0
C0060580	TUC2 Misc Valve Replace 2024		0.0
C0060564	TUC1 Misc Valve Replacement 2024		0.0
C0060259	POA LS Quarry Refurb. 2024	-	0.0
C0060815	POT - PE Nitrogen Generator		0.0
C0060775	POT - South Boiler Feed Pump Refurb		0.2
C0062123	143H-Mount Uniacke Substation		0.1
C0053214	76W-T1 Transformer Replacement	-	0.0
C0050852	10V-T1 Transformer Replacement	-	0.0
C0031048	91H-T11 Transformer Replacement	-	0.0
C0066684	LIN3 UU Bottom Ash Refurbishment	-	0.1
C0061786	30N-412 HWY 242 Fundy Shore Removal	-	0.0
C0060769	POT - Conveyor & Fuel Handling Refu		0.0
C0066503	BGT1 Engine P686598 9th Stage Blade	-	0.0
C0060716	CT Rotolign Tool Kit	-	0.0
C0066723	TUC3 Motor Refurbishments 2024	-	0.0
C0066724	TUC2 Motor Refurbishment 2024	-	0.0
C0066725	TUC1 Motor Refurb 2024	-	0.0
C0054995	2023 Inaccessible PCB Transf Rep	-	0.2
C0066790	TUC1 Stack Refurbishment 2024	-	0.0
C0066791	TUC2 Stack Refurbishment 2024	-	0.0
C0066686	LIN3 UU HEP/FAC Refurbishment 2024	-	0.2
C0060726	CT BGT2 Battery Replacement 2024		0.0
C0060269	POA BFP Rebuild		0.7
C0061361	TRE5 - Conveyors Refurbishment 2024		0.0
C0061359	TRE6 - Misc. Valves Refurb 2024	-	0.0
C0061371	TRE - Common Water Replacement		0.0
C0052055	2023/2024 Trans ROW Widening 69kV	-	0.0
C0064128	Dec 18, 2023 Level 3 Storm Subs	-	0.0
C0060503	LIN Siding Refurbishment 2024		0.0
C0039029	LIN3 Ash Incline Refurbishment 2024	-	0.0
C0064124	IR-700 Pine Tree Comm Solar 82S-303	-	0.0
C0057142	New Distribution ROW Phase 9		0.0
C0060571	TUC1 MTAP Motor Monitoring		0.0
C0061844	BGT Fuel Piping Cable Bridge 2024		0.0
C0067024	527S-311 Big Bras D'or Conversion		0.0
C0060719	PHB - DCS Electrical Upgrade 2024		0.0

C0064223	TUC1 Boiler Tube Leak DEC2023		0.0
C0064224	TUC3 Boiler Tube Leak DEC2023		0.0
C0060344	LIN Plant Lighting Upgrade 2024	-	0.0
C0060383	LIN Coal Plant Structur Refurb 2024	-	0.0
C0052537	POA Coal Feeder Cntrl Upgrade 2023		0.0
C0060483	LIN Grating Refurbishment 2024	-	0.0
C0060567	LIN Fly Ash System Refurb 2024	-	0.0
C0060643	LIN Facilities Upgrades 2024	-	0.0
C0060612	LIN Electric Actuator Upgrade 2024	-	0.0
C0060645	LIN CW Screen Refurbishment 2024	-	0.0
C0060611	LIN 4160 600V Breaker Refurb 2024	-	0.0
C0060463	LIN GSCW Sm Bore Piping Refurb 2024	-	0.0
C0061370	LIN Plant Door Refurbishment 2024	-	0.0
C0052497	POA Coal Crusher Refurbishment	-	0.0
C0060818	LIN Coal Stacker Refurbishment 2024	-	0.0
C0060644	LIN Precipitator Refurbishment 2024	-	0.0
C0061205	POA Elevator Repair	-	0.0
C0060738	PHB - Condensate Drains Tank Replac		0.1
C0067003	99V-314GB Add Second Phase at Sunri		0.0
C0060736	PHB - Lighting Upgrades 2024		0.0
C0067005	93V-313 Meteghan Voltage Correction		0.0
C0060776	POT- Polisher Valves Soloroid Pan		0.0
C0060709	BGT1 Controls Upgrade		0.0
C0061263	LIN Ash Site Winter Cover 2024	-	0.0
C0051593	LIN1 ACW Strainer Replacement 2024	-	0.0
C0060561	TUC Platform & Ladders 2024	-	0.0
C0060600	TUC Handrail Program 2024		0.0
C0060260	POA Turbine Valves Refurb.	-	0.0
C0060903	POA Coal Transformer Replacement		0.0
C0061374	TRE- Rotating Equipment Guards 2024		0.0
C0061369	TRE - LED Lighting 2024		0.0
C0062103	TRE0 Floor Plates and Grating 2024		0.0
C0061358	TRE5- Misc. Valves Refurb. 2024		0.0
C0064511	Jan 10, 2024 Level 3 Storm-Transm		0.0
C0064512	Jan 10, 2024 Level 3 Storm-Substa	-	0.0
C0060779	LIN Coal Crusher Refurbishment 2024	-	0.0
C0054235	LIN CW ACW Strainer Replacement	-	0.0
C0061383	LIN Wastewater Pump/Valve Refurb	-	0.0
C0060663	LIN Guard and Rail Upgrade 2024	-	0.0
C0060772	LIN BFP Recirc Line Replace 2024	-	0.0
C0061343	TRE - Ash Site Management 2024	-	0.1
C0060750	2024 Vault Replacement		0.0
C0068269	LIN2 GSCW Piping Refurbishment 2025	-	0.0
C0068260	LIN2 Grating Refurbishment 2025	-	0.0

C0068262	LIN2 Guard and Rail Upgrade 2025	-	0.0
C0068259	LIN2 Fly Ash System Refurb 2025	-	0.0
C0068807	POA DCMS Upgrades 2025	-	0.0
C0068258	LIN2 Electric Actuator Upgrade 2025	-	0.0
C0068045	POA Machinery Guarding 2025	-	0.0
C0068029	POA SUB Upgrades 2025		0.0
C0068025	POA - Valve Component Repl.2025		0.0
C0074148	RC May St Crossing Gate U&U		0.0
C0073889	87H-312 Musquodoboit Harbour Bridge	-	0.0
C0068023	POA - LS System Refurbishment 2025		0.0
C0070451	2026 Switch and Breaker Replacement		0.0
C0053719	Customer Contributed > \$75k	-	0.0
C0061223	POA LS Piping Replacement		0.0
C0061333	TRE - HVAC System Refurbishment		0.0
C0070846	TRE6 U&U Waterwall Tube Leak Repair	-	0.0
C0060819	LIN HFO/LFO Line Refurbishment 2024	-	0.0
C0070866	LN1 UU FAC Refurbishment 2024	-	0.1
C0074210	ICP Sluice Channel Covers U&U	-	0.0
C0074248	TUC1 Stack Protective Envelope		0.0
C0073931	TRE6 U&U External Wtrwall Tube Rep		0.0
C0074291	TUC2 Stack Protective Envelope		0.0
C0074308	TUC 3 Stack Protective Envelope		0.0
C0068264	LIN2 Precipitator Refurb 2025	-	0.0
C0068255	LIN2 4160 600V Breaker Refurb 2025	-	0.0
C0068268	LIN2 SCC Refurbishment 2025	-	0.0
C0068266	LIN2 Boiler Refurbishment 2025	-	0.1
C0069130	POT - East / West Polisher Resin Re		0.1
C0068939	POT - Breaker Replacements / Upgrad		0.0
C0068886	PHB - DCS Electrical Upgrade 2025		0.0
C0068265	LIN2 Ash Incline Refurbishment 2025	-	0.0
C0067927	HYD CT Test Set	-	0.0
C0069106	POT-CW Pump House Refurbishment		0.1
C0068657	TRE - Floor Plates and Grating 2025		0.0
C0069060	TUC1 4160V Relay Data Acquisition		0.0
C0074391	TUC1 Elevator Brake Refurbishment		-
C0070886	POT-UU Turning Gear Refurbishment	-	0.0
C0070966	POT-SD UU Generator Bus Flex Link R	-	0.0
C0071006	99H-312 Farrell Street Feeder Upgra	-	0.0
C0060548	TUC WWTP Roof Replacement 2024		0.0
C0070766	LIN4 UU SH4 Boiler Tube Refurb 2024	-	0.0
C0074368	LIN2 UU Boiler Tube Refurb 2025	-	0.0
C0074369	LIN3 UU Boiler Tube Refurb 2025	-	0.0
C0073888	TRE6 U&U Low Load Valve Rebuild		0.0
C0069057	TUC2 Electric Actuators 2025		0.0

C0069058	TUC3 Electric Actuators 2025	-	0.0
C0069056	TUC1 Electric Actuators 2025	-	0.0
C0074488	TRE5 U&U Feb Boiler Tube Replace		0.0
C0070868	LEDR Radio Link Replacement		0.0
C0068041	POA 4KV 600V Breaker Refurb 2025		0.0
C0068053	POA Actuator Upgrades		0.0
C0068267	LIN2 Misc. Valve Refurbishment 2025	-	0.0
C0068768	TRE - Facility Refurbishment		0.0
C0068902	TRE "6A" Polisher Resin Replacement		0.0
C0069083	TUC6 Electric Actuators 2025		0.0
C0069067	TUC1 Natural Gas Valves Refurb 25		0.0
C0069073	TUC2 Nat Gas Valves Refurb 2025		0.0
C0069081	TUC3 Natural Gas Valves Refurb 2025		0.0
C0070767	LIN4 UU A CW Pmp Bear. Replace 2024	-	0.0
C0071168	POA UU South Vortex Finder Repl.		0.1
C0071269	POA UU Generator Bearing Refurb.		0.1
C0071229	POA UU RH1 Tube Replacement 2024		0.0
C0070926	78W-301GA Add Second Phase to Heckm		0.0
C0071248	2024 PCB Poletop Sampling and Repla	-	0.7
C0071349	POT- SD UU ID Fans Refurbishment		0.0
C0071107	POT- SD UU Vacuum Pump System Refur	-	0.0
C0071388	TUC1 North FD Fan Refurb 2024	-	0.0
C0069070	TUC1 Motor Refurb 2025		0.0
C0069075	TUC2 Motor Refurb 2025		0.0
C0060264	POA Forklift Replacement	-	0.0
C0069082	TUC3 Motor Refurb 2025		0.0
C0069084	TUC6 4160v/600v Motor Refurb 2025		0.0
C0060265	POA Sewer Discharge Ctrlrs upgrade	-	0.0
C0068878	BGT1 Battery Charger Replacement		0.0
C0068876	BGT2 Battery Charger Replacement	-	0.0
C0068877	BGT3 Battery Charger Replacement		0.0
C0068912	TUC2 Boiler Refurb 2025		0.1
C0069016	TUC2 DCS HMI Upgrade 2025		0.0
C0049192	HYD GUL Generator Refurbishment		0.2
C0069061	TUC2 MCC Refurbishment 2025		0.0
C0074372	TUC1 Boiler Burner Frnt Replacement	-	0.0
C0074631	TUC2 FAC Refurb 2025	-	0.0
C0074649	TUC2 HEP Refurb 2025	-	0.0
C0074651	TUC2 CW Expansion Joint Replac 2025	-	0.0
C0069074	TUC2 4160v Relay Data Acquisition		0.0
C0069568	TUC PCB Lighting Removal		0.0
C0068879	VJ2 Battery Replacement 2024		0.0
C0069008	TUC Platforms and Ladders 2025		0.0
C0069072	TUC2 Control Valve Repalcements		0.0

C0071429	RC Maintenance Bldg Roof Refurb U&U		0.0
C0071468	TUC WTP Acid Pump & Valve Refurb		0.0
C0071568	RC Mile 14 Culvert Blockage U&U		0.0
C0070086	10H-T2 Transformer Replacement	-	0.0
C0070909	70W-T51 Transformer Replacement	-	0.0
C0071588	POA UU Station Air Comp, Rebuild	-	0.0
C0071668	TRE5 U&U Waterwall Tube Leak Repair		0.0
C0061367	TRE - Security Upgrades		0.0
C0061268	LIN2 O2 Analyzer Replacement 2024	-	0.0
C0067524	4S-332 - Charlotte St Re-design Ph3	-	0.0
C0067546	4C-430 James River Bridge Replace		0.0
C0071768	TUC6 Lift Station Pump Replacement	-	0.0
C0071788	TUC2 HP Bearing 1 & 2 Replacement		0.0
C0070686	TUC1 Seal Oil Lube Oil Refurb 2024		0.0
C0071148	TUC WTP RO Membrane Replace 2024		0.0
C0071408	TUC3 Recirc Line Replacement 2024		0.0
C0061335	TRE - Fish Barrier Screen Upgrades		0.0
C0071007	TRE5 U&U Mill Classifiers Refurb		0.0
C0068887	TUC3 Turbine Valves Refurbishment		0.1
C0070929	104S-313 Big Hill Highway Crossing		0.0
C0060553	TUC Service Air Compressor South		0.0
C0059624	AMO LIN1 Enhanced Monitoring		0.0
C0067404	LIN3 UU CW Pipe Refurbishment 2024	-	0.0
C0067405	LIN4 UU FAC Refurbishment 2024	-	0.0
C0067685	LIN UU Crane Refurbishment 2024	-	0.0
C0061351	TRE6 - Turbine Generator Fire Suppr		0.0
C0061485	TRE6 Turbine Generator Steel Column		0.0
C0060785	POT - Stores Room Fire Protection		0.0
C0067943	LIN4 UU SH5 Tube Refurbishment 2024	-	0.1
C0060267	POA Structural Steel Access Refurb.	-	0.0
C0071968	TUC1 Cooling Lifting Jib Replace	-	0.0
C0068632	TUC Stack Worker Protective Envelop		0.0
C0071630	1N-405G Edmond Lynds Bridge Replace		0.0
C0071891	POA UU HEP/FAC Refurbishment 2024	-	0.0
C0070646	57C-426H-Stillwater Phase Extension		0.1
C0071328	LIN4 UU Turbine Post Install 2024	-	0.0
C0062823	POA Guardrails	-	0.0
C0052457	POA Coal Chute Replacements	-	0.0
C0060549	TUC Facilities Upgrade 2024		0.0
C0067823	LIN1 UU A CW Pump Bearing Replace	-	0.0
C0061336	TRE5 Coal Feeder Inlet Gate Refurbi	-	0.0
C0061356	TRE - Overhead / Person Door Refurb		0.0
C0061346	TRE6 - PE HEP / FAC Refubishments	-	0.0
C0061349	TRE - No.6 Polisher Resin Replaceme		0.0

C0068207	TUC1 HP Heater #5 Refurbishment	-	0.0
C0061005	POA Cell Capping 2025	-	0.1
C0068048	POA Fuel Day Tank and U/G Line Repl	-	0.0
C0060263	POA Oil Water Separator Tank Refurb		0.0
C0067112	L5012 Replacements and Upgrades		0.1
C0068250	HYD LEQ Thrust Pad Replacement	-	0.0
C0071808	126H - 314 Porters Lake New Feeder		0.0
C0060747	PHB - Turbine & Generator Fire Spri		0.0
C0068009	LIN3 UU B FD Fan Refurbishment 2024	-	0.0
C0067423	TRE5 U&U 5-2 CW Pump Motor	-	0.0
C0068306	TUC1 4kv600v Breaker Replacement 25	-	0.0
C0068307	TUC2 4kv600v Breaker Replace 2025	-	0.0
C0068308	TUC3 4kv600v Breaker Replace 2025	-	0.0
C0060547	TUC Heat Tracing Upgrades 2024		0.0
C0068387	TUC1 Boiler Tube Leak JUN24	-	0.1
C0068408	HYD Protection Assessment		0.0
C0068328	TUC1 CW Inlet Pipe Base Refurb	-	0.1
C0060576	TUC1 Condensate Extract Pump Refurb		0.0
C0060545	TUC1 CW Pump Refurb 2024		0.0
C0061204	POA LS Crusher Sys. Opt. 2024	-	0.0
C0067363	WIN DIG WTG10 Generator Replacement	-	0.0
C0072270	POT-SD UU CW Piping Refurbishment	-	0.0
C0068615	VJ Trench Fuel Piping Replace 2024	-	0.0
C0061546	L6514 Replacements and Upgrades		0.0
C0061551	L7009 Replacements and Upgrades Pha		0.2
C0061547	L7022 Replacements and Upgrades		0.1
C0061387	2024 2025 Wood Pole Retreatment Pro	-	0.0
C0061743	L6038 Realignment		0.1
C0072248	POT-SD UU Exciter Refurbishment		0.0
C0072048	PHB-SD UU Wennberg Screw Refurbishm		0.0
C0072329	POT-SD UU Pressure Relief Valve R		0.0
C0071669	LIN3 UU SVR Filter Install 2024	-	0.0
C0072549	TUC3 Boiler Tube Leak NOV24		0.0
C0072568	TRE6 UU Stack Breach Duct Refurb	-	0.3
C0072589	HYD LEQ Lower Guide Bearing Replace		0.1
C0072628	TUC1 Boiler Tube Leak NOV24		0.0
C0071870	LIN3 UU Main FW Contr Valve Refurb	-	0.0
C0072348	LIN1 UU Condenser Vac Pump Replace	-	0.0
C0072210	POA UU Ash Screw Cooler Refurb	-	0.0
C0072710	TUS Bleed Valve Replacement		0.0
C0072888	POT- SD UU GSCW Pump Replacement		0.0
C0072909	LIN1 UU Boiler MSV Refurbishment	-	0.1
C0053855	1H-415-Reinsulate Marginal Rd	-	0.0
C0061883	129H - Kearney Lake Substation Rebu	-	0.0

C0060749	2024 Padmount Replacement		0.1
C0073070	TUC North South Buoy Refurb		0.0
C0072976	18V-413G Little Meander Bridge Pole		0.0
C0072609	2024 Substation Fence Upgrades		0.1
C0072328	57S-401 Targeted Device Replacement		0.2
C0072089	2P Mobile Transformer Replacement		0.0
C0071889	77V-T1 Transformer Replacement		0.0
C0071888	92H-T61 Transformer Replacement		0.0
C0073114	TUC2 Boiler Waterwall Tube Replace	-	0.0
C0073048	62H-301 Lancaster Woodland Roundabo		0.0
C0042526	HYD ULF2 Generator Refurbishment	-	0.0
C0068567	POT-SD UU HTSH Bend Replacement2024	-	0.2
C0067447	POT- PE Condensate Polisher Skid Re	-	0.0
C0050642	HYD DIB2 Rotor Ground Refurbishme		0.0
C0068772	POT-SD UU HEP Inspection & Repairs	-	0.1
C0068773	509V-301 Brier Island Sub Cable Rep	-	0.0
C0061368	TRE - Nitrogen Generator		0.0
C0061357	TRE6- Boiler Safety Valve Refb 2024		0.0
C0068986	LIN Manutair A Vacuum Pump Replace	-	0.0
C0069127	TUC5 Battery Replacement 2024	-	0.0
C0069108	TUC1 FAC Refurb 2024	-	0.0
C0069110	TUC1 HEP Refurb 2024	-	0.0
C0069146	TUC3 HEP Refurb 2024	-	0.0
C0064983	LIN1 UU Vacuum Pump Line Replace	-	0.0
C0072712	LIN1 UU Condenser Coating Refurb	-	0.0
C0073050	PHB- SD UU Precip Collecting Plates	-	0.0
C0070486	Lower Great Brook Stoplog Refurbish		0.2
C0061545	L6006 Replacements and Upgrades		0.8
C0068309	PHB - SD UU FAC 2024	-	0.0
C0069167	TUC6 Misc Valve Refurb U&U 2023	-	0.0
C0069151	TUC WTP Tank 3 Cation Vessel Replac	-	0.0
C0060689	LIN1 Boiler Refurbishment 2024		0.1
C0069366	TUC3 Boiler Additional Findings 24	-	0.0
C0061550	L5031 - Hubbards to East Chester	-	0.1
C0060604	TUC2 Lube Oil System Refurb		0.0
C0062026	HYD - LUM Capital Available	-	0.0
C0069368	TUC3 South BFP Refurb 2024	-	0.0
C0072548	HYD MAL Asbestos Abatement		0.0
C0073249	TUC2 DC Lube Oil Impeller Replace		0.0
C0073328	HYD GUL Rotor Lead Reinsulation		0.0
C0073368	Malay Falls Rubber Dam Refurbishmen		0.0
C0073288	TRE6 U&U Dec Tube Leak Repair	-	0.0
C0072989	TRE5 U&U Lower Waterwall Tube Leak		0.0
C0070366	2025 TripSaver Additions		0.0

C0067403	TRE5 PE Secondary Air Heater	-	0.1
C0069289	6W-201 - Offload to 50W		0.0
C0061344	TRE6 - PE HEP / FAC Refurbishments	-	0.0
C0067464	TRE6 U&U Bunkerette Replacement	-	0.0
C0060273	POA MCC Cabinets Refurb.		0.0
C0061203	POA Damper Upgrades		0.0
C0068566	LIN DCS Upgrade 2026	-	0.1
C0061329	TRE - Plant Louvers Refurbishment	-	0.0
C0069392	12V-T1 Transformer Replacement	-	0.0
C0069394	16N-T1 Transformer Replacement	-	0.0
C0053234	96H-T1 Transformer Replacement		0.0
C0072928	TRE5 U&U CW Screens Enhancement		0.0
C0068900	TRE - Fish Barrier Screen Upgrades		0.0
C0067709	TRE0 Demin. Plant Upgrades		0.0
C0073408	LIN1 UU B Air Heater Gearbox Replac	-	0.0
C0073432	POT- SD UU Stores Room Refubishment		0.0
C0073130	WIN POTWF WEC 5 Rear Bearing Failur		0.0
C0068608	TRE - Asbestos Abatement 2025		0.3
C0070347	2025 Hydraulic Recloser Replacement		0.0
C0073491	LM6000 - 191-443 Engine Refurbishme		0.0
C0069547	PHB - SD UU HEP Refurbishment 2024	-	0.0
C0060925	POA Coal Transformer Cable Repl	-	0.1
C0060270	POA Coal Dust Collector Rebuild	-	0.0
C0061364	TRE6- Burner Impeller Replacement		0.0
C0061353	TRE6- 6 A&B CW Pump Motorized Dis v		0.0
C0069766	PHB-SD UU PB3 Side Seal Replaceme	-	0.1
C0069768	PHB-SD UU Turbine Extraction Valv	-	0.0
C0067866	2024 Substation Recloser Replacemen	-	0.0
C0061334	TRE - 4KV Breaker Replacements 2024		0.0
C0069848	TUC2 FAC Refurb 2024	-	0.0
C0061354	TRE6 - Ash Hoppers Nuclear Gauge Re	-	0.0
C0069827	PHB- SD UU Distribution Conveyor Re	-	0.0
C0069847	TUC2 HEP Refurb 2024	-	0.0
C0073188	Replacement of 87S GT1 H3 Bushing	-	0.0
C0068030	POA LS Quarry Refurbishments 2025		0.0
C0068941	POT - Miscellaneous Valve / Compone		0.0
C0067963	POA LS Quarry Reclamation 2025	-	0.0
C0068052	POA Access Improvement 2025	-	0.0
C0073608	PHB - SD UU Lower Furnace Tube Leak		0.0
C0068037	POA Plant Lighting Upgrades 2025		0.0
C0068051	POA Facilities/Security upgr. 2025	-	0.0
C0068190	LIN Plant Lighting Upgrade 2025	-	0.0
C0009323	POA SA Compressor Upgrade	-	0.0
C0068148	LIN Coal Plant Structur Refurb 2025	-	0.0

C0068026	POA Coal System Refurb 2025	-	0.0
C0068024	POA Ash System Refurb 2025		0.0
C0068036	POA Overhead Door Refurb 2025		0.0
C0068249	LIN34 GSCW Piping Refurb 2025	-	0.0
C0068194	LIN Sootblower Refurbishment 2025	-	0.0
C0068164	LIN Electric Actuator Upgrade 2025	-	0.0
C0070827	99V-314G-Lake George Line Extension		0.0
C0069270	2025 SCADA/EMS Upgrade	-	0.0
C0070055	ICP #7 Stacker Refurb		0.0
C0069534	IR 669 NU - Higgins Mountain Wind	-	0.1
C0069687	M10905 Interconnection Study Decisi	-	0.0
C0069269	TUC3 Seal & Lube Oil Backwash	-	0.0
C0070109	ICP #5 Canon Dust Suppression		0.0
C0068787	TRE6 U&U PA Flow Measurement	-	0.1
C0060788	POT - Roadway Repairs 2024		0.0
C0070326	TUC2 North CW Pump Discharge Refrub	-	0.0
C0070346	POA UU Bustle Air Expan. Joint Rep	-	0.0
C0069967	TUC1 Air Heater Hopper Case Refurb		0.0
C0069021	TUC Handrail Program 2025		0.0
C0069026	TUC Lighting Program 2025		0.0
C0069063	TUC Electric Panel Replacements 25		0.0
C0068909	TUC Facilities Upgrade 2025		0.0
C0072929	POA UU Condenser Tube Repair 2024	-	0.0
C0069022	TUC Rotating Equipment Guard 2025		0.0
C0069028	TUC Sensors & Alarms 2025		0.0
C0069029	TUC Concrete Floor Refurb		0.0
C0069626	PHB- SD UU Wennberg South Screw Re	-	0.0
C0068145	LIN Coal Crusher Refurbishment 2025	-	0.0
C0068127	LIN 4160 600V Breaker Refurb 2025	-	0.0
C0068191	LIN Precipitator Refurbishment 2025	-	0.0
C0068193	LIN Siding Refurbishment 2025	-	0.0
C0068189	LIN Plant Heating Upgrade 2025	-	0.0
C0068169	LIN Grating Refurbishment 2025	-	0.0
C0068170	LIN Guard and Rail Upgrade 2025	-	0.0
C0068187	LIN Mill Refurbishment 2025	-	0.0
C0052013	LIN WTP Demin Upgrades 2023	-	0.0
C0031047	85S New Generator Breakers	-	0.0
C0053076	14C-211 Boudreauville Rd Conversion		0.0
C0069288	TRE6 U&U 6B Boiler Feed Pump	-	0.0
C0070447	BGT Compressor Refurbishments	-	0.0
C0060603	TUC2 Replace Turbine RTDs		0.0
C0068655	LM6000 191-332 Life Extension	-	0.1
C0068263	LIN2 Mill Refurbishment 2025	-	0.0
C0073508	TRE5 U&U Dec BoilerTube Replacement	-	0.0

C0068168	LIN Fly Ash System Refurb 2025	-	0.0
C0068196	LIN TWW Piping Replacement 2025	-	0.0
C0068252	LIN Common Water System Refurb 2025	-	0.0
C0068188	LIN Pac System Upgrade 2025	-	0.0
C0068626	TRE - LED Lighting 2025		0.0
C0068667	TRE5 - Misc. Valves Refurbish. 2025		0.0
C0068770	TRE6 - Misc. Valves Refurb 2025		0.1
C0071528	FLISR Project	-	0.0
C0060164	LIN Boiler Fill Pump Suction Repl.		0.0
C0039046	LIN Ash Silo Refurbishment 2024	-	0.0
C0068669	TRE5 - Conveyors Refurbishment 2025		0.0
C0074108	ICP Truck Gate U&U	-	0.0
C0074110	RC TRMC Roof Structure U&U		0.0
C0068826	PHB - Lighting Upgrades 2025		0.0
C0076413	126H-312GA Route 207 Lawrencet		0.0
C0075508	88W Pleasant St Transformer Refurbi	-	0.0
C0070666	TRE5 - PA Hot/Cold Air Drive Replac		0.1
C0072808	Synchronous Condensers	-	0.0
C0079999	IT - Oracle Fusion Implementation	-	1.1
C0080007	IT - Payroll (Peoplesoft)	-	0.1
C0080009	IT - MyAccount	-	0.2
C0080011	IT - MV90		0.1
C0080013	IT - AMI - HES	-	0.0
C0080015	IT - AMI - MDMS	-	0.1
C0080017	IT - Energy Trading - Allegro	-	0.0
C0080019	IT - Accounts Payable	-	0.1
C0080021	IT - Certent Disclosure Manager	-	0.0
C0080023	IT - Distribution Grid Control & Op	-	0.1
C0080025	IT - Align Fuels & Plant Info (PI)	-	0.0
C0080027	IT - Emera Energy	-	0.0
C0080029	IT - Asset Inventory - Maximo	-	0.0
C0080031	IT - OT Hardening	-	0.1
C0080033	IT - Compute	-	0.4
C0080035	IT - Identity	-	0.0
C0080037	IT - Middleware	-	0.0
C0080039	IT - Network	-	0.0
C0080041	IT - Data		0.0
C0080043	IT - PKI	-	0.0
C0080045	IT - PC Replacement	-	0.0
C0080047	IT - Recovery Program Office	-	0.0
C0080201	TRE6 - U&U HEP		0.1
C0067908	POA Boiler Refractory Refurb 2025		0.3
C0069588	TUC2 - Oil Burner Front Valve Repla		0.0
C0060573	TUC1 Replace WI PLC		0.0

C0006418	HYD WRC Tailrace Rock Bolting Ph2	-	0.0
C0074654	16W-301G-Highway One Rebuild		0.0
C0074671	57W-401 -New Elm Road Voltage Conve		0.0
C0068952	2025 PCB Poletop Sampling and Repla	-	0.2
C0069126	POA CW Screen Wash Pump Replacement		0.0
C0068689	PHB - Boiler Refurbishment 2025		0.3
C0068908	PHB - Conveyors & Handling Systems		0.1
C0068933	PHB - BAS Upgrade Phase 1		0.0
C0068890	TRE - Ash Site Management 2025		0.0
C0069013	TUC Station Fuel Oil Upgrade Ph2		0.0
C0068230	LIN3 Misc. Valve Refurbishment 2025		0.0
C0068192	LIN Reclaim Refurbishment 2025	-	0.0
C0068166	LIN Facilities Upgrades 2025	-	0.0
C0068204	LIN Wastewater Piping Replace 2025	-	0.0
C0068229	LIN3 Boiler Refurbishment 2025	-	0.0
C0050479	LIN3 Aux Air Upgrades 2025	-	0.0
C0068228	LIN3 Air Preheater Seal Refurb 2025		0.0
C0068233	LIN4 Boiler Refurbishment 2025	-	0.1
C0060803	LIN4 SCC Refurbishment 2024	-	0.0
C0068234	LIN4 Misc. Valve Refurbishment 2025	-	0.0
C0060717	CT BGT3 Inverter Replacement		0.0
C0061527	POA Oil Purification System	-	0.0
C0074848	50W-411- Milton Station Service		0.0
C0074768	POA UU RH1 Refurbishment	-	0.0
C0068771	TRE6 Conveyors Refurbishment 2025		0.0
C0068623	TRE - Road and Grounds Refurbishmen		0.1
C0069048	TUC2 CW Inlet Screen Refurb		0.0
C0074470	TRE5 U&U Coal Feed Pipe Enhancement		0.0
C0050795	TRE - Common Water Replacement 2023		0.1
C0072768	TRE6 U&U PAC Upgrades		0.0
C0068231	LIN4 Boiler Erosion Reduc Sys 2025	-	0.0
C0068235	LIN4 RH1 Boiler Tube Replace 2025	-	0.1
C0068453	LIN4 DA Heater Tray Refurb 2025	-	0.0
C0068183	LIN HFO System Upgrades 2025		-
C0068236	LIN4 North Water Wall Replace 2025	-	0.0
C0075269	LIN1 UU CW Screen Boot Refurb 2025	-	0.0
C0068659	TRE5 - IP-LP Turbine Refurbishment		0.6
C0068625	LIN SCC Hydraulic Drive Replacement	-	0.0
C0075204	LIN1 UU Flame Scanner Replace 2025	-	0.0
C0075206	LIN2 UU A CW Screen Refurb 2025	-	0.0
C0075348	LIN1 UU FAC Refurbishment 2025	-	0.0
C0075349	LIN2 UU FAC Refurbishment 2025	-	0.0
C0075350	LIN3 UU FAC Refurbishment 2025	-	0.0
C0075351	LIN4 UU FAC Refurbishment 2025	-	0.1

C0074130	Robie Street Underground	-	0.0
C0075372	HYD TUS Tainter Gate 3/4 Anchors		0.0
C0069114	POT- PE WTP Graver PLC Upgrades		0.0
C0053118	TUC Storage Building 2023		0.0
C0075468	TRE5 U&U SSH Inlet Boiler Tube Repl		0.0
C0075611	TUC1 LPT Last Stage Blade Refurb	-	0.1
C0075612	TUC1 Boiler Tube Leak MAR25	-	0.0
C0068769	TRE6 - Boiler Refurbishment		0.5
C0068671	TRE6 Mill Refurbishment		0.3
C0068672	TRE6 - Waterwall Replacement		0.2
C0075528	TUC2 North BFP Recirc Valve Replace		0.0
C0075753	AMO BI Portal	-	0.0
C0075768	TUC1 FAC Refurb 2025		0.0
C0075771	TUC1 HEP Refurb 2025		0.0
C0069112	POT - Fire Protection Upgrades 2025		0.1
C0069059	TUC6 MCC Refurbishment 2025		0.0
C0069062	TUC3 MCC Refurbishment 2025		0.0
C0068960	99H Farrell St Feeder Addition	-	0.0
C0068042	POA Wellfield Communication Upgrade	-	0.0
C0068038	POA Building HVAC Refurbishment		0.0
C0068031	POA Equipment Monitoring Upgrades		0.0
C0060266	POA PLC Upgrades		0.0
C0068936	PHB - Phosphate Meter		0.0
C0068937	POT - Boiler Refurbishment 2025		0.5
C0067906	POA Boiler Refurbishment 2025		0.8
C0074849	12V-302G Karsdale Reconductor		0.0
C0075668	HYD STM Asbestos Abatement		0.7
C0068668	TRE5 - Burner Front Refurbishment		0.3
C0070006	TRE5 5-2 Vacuum Pump Replacement		0.0
C0068344	HYD PCB Removal		0.0
C0068666	TRE5 - Boiler Safety Valve Refurbis		0.0
C0068610	TRE - HVAC System Refurbishment		0.0
C0068661	TRE 4KV Motor Refurbishment		0.1
C0067950	POA Coal Gallery Refurbishment		0.3
C0050641	CT VJ2 Free Turbine Full Refurbishm		0.0
C0076152	TUC3 Boiler Tube Leak MAR25		0.0
C0068905	TUC1 Boiler Refurbishment 2025		0.0
C0076091	HYD PAR Lower Guide Bearing Replace		0.1
C0068911	TUC1 Cond Up Inlet Piping Replace		0.0
C0068907	TUC HVAC Refurb 2025		0.0
C0069034	TUC1 CW Inlet Screen Refurb		0.0
C0075588	IT - Load Forecasting Enhancements	-	0.0
C0069051	TUC Dionex Replacement		0.0
C0076072	PHB-SD UU Stacker Conveyor Refurbis	-	0.2

C0068046	POA Ladder Upgrades	-	0.0
C0060944	POA Polisher Resin Repl.		0.0
C0068903	TUC6 CW Pump Refurb 2025		0.0
C0069010	TUC West Bird Screen Doors		0.0
C0073965	TRE5 U&U Burner Nest Wtrwall Replac		0.1
C0076271	TRE5 PE FAC Refurbishment 2025		0.1
23127-D010-840	D010 Provincial Distribution ROW	-	0.0
C0076071	TRE5 U&U 5-5 Feedwater Heater Refur		0.1
C0072911	TRE5 U&U Main Feedwater Ele In Valv	-	0.0
C0076013	HYD 4th Lake Switchgear Safety Upgr	-	0.0
C0041511	AMO POT Enhanced Monitoring		0.0
C0075911	2025 Substation Fence Upgrades	-	0.0
C0076273	Bear Head Ash Management Site - Lif		0.0
C0075973	PHB - PE Emissions Performance Stud		0.0
C0076193	BGT4 Engine P686621 Case Refurb	-	0.1
C0068662	TRE5 Baghouse Filter Replaceme		0.3
C0068032	POA Motor Overhauls		0.0
41229-SB17	LIN - Cable Spreading Rooms Fire Pr	-	0.0
20916-T004-743	TRANSMISSION SUBSTATION ADDITION/MO		0.0
44985-T807	Replace 230kV Kearney Disconnect Sw		0.0
48047-T870	Trans Inspection Programs	-	0.0
47950-T881	L-5017 Replacements & Upgrades	-	0.0
47915-T931	L5053 Replacements and Upgrades		0.0
49948-T960	2017/2018 Isolated Structure Replac	-	0.1
49034-D737	530W-201 John's Cove Causeway Reins	-	0.0
17789-H001-410	BER - HYDRO EQUIPMENT REPLACEMENTS		0.0
CONV-H001-411	H001-HYDRO EQUIPMENT RPLC SIS		0.0
20604-H001-435	ANN - HYDRO EQUIPMENT REPLACEMENTS	-	0.0
17832-H001-450	SHH - HYDRO EQUIPMENT REPLACEMENTS	-	0.0
17833-H001-460	BLR - HYDRO EQUIPMENT REPLACEMENTS		0.0
17834-H001-470	MER -HYDRO EQUIPMENT REPLACEMENTS	-	0.0
20613-H001-491	MIL - MAINT HYDRO EQUIPMENT REPLACE	-	0.0
47272-H006-470	HYD - Gate Refurb Routine - MER		-
46253-H763	HYD - Lequille Tailrace Gate		-
49036-H766	HYD - Avon 2 Controls Upgrade		0.1
47650-H774	HYD - Annapolis Decision Analysis		2.0
49272-H776	HYD - Miller Lake Dam Refurbishment	-	0.1
50574-H794	PE Sissiboo Falls Main Dam Refurb		-
50580-H795	PE Weymouth Falls Intake Refurb	-	0.1
11744-P001-032	FAC - Property Improvements		-
26526-P002-571	METER SHOP - TOOLS AND EQUIPMENT		-
11541-P002-742	Tools And Equipment - West	-	0.0
16073-P010-615	SCADA IMPROVEMENTS ROUTINE		0.0
18620-P015-410	BER-HYDRO-TOOLS AND EQUIPMENT		0.0

18625-P015-460	BLR-HYDRO-TOOLS AND EQUIPMENT	-	
18627-P015-480	WRC-HYDRO-TOOLS AND EQUIPMENT	-	
16551-P027-635	TELECOMMUNICATION RADIO AND FIBRE O	-	0.0
51483-P158	IT-Public Key Inf-Certificate Auth	-	0.0
38897-P816	FAC Enviro Property Remed Routine		0.0
40305-P867	Pi Portal Upgrade	-	0.0
47751-P975	ECC Dynamic Line Rating Implementat	-	0.0
C0011005	AMO PE LIN1 Major Outage Support	-	
C0011189	D-2H-411-Cowie Hill UG system repl		0.0
C0003678	P002-722 - NORTHEAST TOOLS		0.0
52185	D-50N-410 Rebuild Phase 2	-	0.0
43268	9W-B53 Tusket Replace Structure	-	0.0
52046	LIN Precipitator Controls Upgrade	-	
52258	2018/2019 Isolated Structure Replac	-	0.0
52320	L6549 2018 Replacements & Upgrades	-	0.0
49942	HYD - Tidewater Facility Repairs		0.3
C0008938	D-542W-311 Brooklyn Conversion	-	0.0
49595	HYD - TUS1 Overhaul		0.0
C0002058	Damage Assessment Enhancements	-	
C0009311	POA Plant Lighting Upgrade		0.0
C0030882	POA Vibration Monitoring		0.0
C0020144	POA Heater Level Controls		0.0
C0030162	LIN Coal Amenities Building Repl.	-	0.0
C0030906	POA Seal Oil Piping Modifications	-	0.0
C0026862	LIN1 CW Pipe Refurbishment		0.0
C0056063	TRE U&U Coal Pile GPS Avoidance Sys	-	0.0
C0050793	TRE LED Lighting upgrade 2023	-	0.0
C0043651	4C-441G- Rear Monastery Rd Reconduc		0.0
C0036407	LIN HFO/LFO Line Refurbishment 2022		0.0
C0039028	LIN1 Ash Incline Refurbishment 2022		0.0
C0052460	POA LS Quarry Reclamation 2023	-	0.4
C0060817	TUC2 8" Inlet Steam Valve Replace		0.0
C0010331	TRE6 Precip Controls Upgrade		0.0
C0061943	TUC1 HEP Refurb 2023		0.0
C0060253	POA LS System Refurb. 2024		0.0
C0060343	POA CW Screenwash Pump Repl.	-	0.0
C0060262	POA Building HVAC Refurb.		0.0
C0055318	TRE U&U Ash Conditioners Refurb	-	0.0
C0071928	652V-212 Kentville Conversion		0.2
C0071954	87W-312 - Dauphiness Mill Lake Rebu		0.0
C0067110	L5532 Replacements and Upgrades		0.0
C0067111	L5023 Rebuild		0.0
C0064724	513N-301 Caribou Overloaded Stepdow		0.0
C0063405	ICP Locomotive Refurbishment 2024		0.0

C0063559	PTMT Conveyor Refurbishment Phase 2		0.0
C0063561	PTMT Pier Facilities Refurb		0.0
C0070049	PTMT Inhaul Conveyor Walkways	-	0.0
C0070051	PTMT Slip Dock Refurb	-	0.0
C0070053	PTMT MCC Breakers & UPS Refurb		0.0
C0066428	70W-312 - Brook Street Phase Extens		0.0
C0070586	22N-603 and 604 Switch Repl L6536		0.0
C0071849	2C-401 Port Hastings Roundab Phase1		0.0
C0070268	2025 Voltage Regulator Replacements	-	0.0
C0072115	L5511 Replacements and Upgrades		0.0
C0075168	16W-301G Short Beach Reconductor		0.0
C0068969	2026 Pennsylvania Breaker Replaceme	-	0.0
C0041321	TRE5 Turbine Turning Gear		0.0
C0076379	PTMT Shuttle Festoon Refurbish	-	0.0
C0076251	2025 Substation Theft Prevention		0.1
C0068966	2026 Merlin Gerin Breaker Repl	-	0.0
C0073388	L8002 Replacements and Upgrades U&U		0.0
C0075448	103H Lakeside Triple CCT Pole Repla		0.0
C0069232	L6021 Replacements and Upgrade Ph1		0.2
C0069231	L8002 Replacements and Upgrade Ph 1		0.6
C0069227	L6516 Replacements and Upgrade Ph 3		0.2
C0073309	IR 677 NU - Wedgeport Wind		0.0
C0080114	HYD HEG Asbestos PCB Remediation		0.0
C0080116	HYD ULF Crane Column Refurbishment		0.0
C0076222	HYD BIF Crane Column Refurbishment		0.0
C0068251	HYD WRC D11 Valve and Housing Repla		0.0
C0080127	LIN4 Condensate Extraction Pump Ref		0.0
C0080142	TUC3 FAC Refurb 2025		0.2
C0080146	TUC1 HEP Refurb 2025 - C0080147		0.1
C0080150	TUC1 HP Turbine Vibration Refurb		0.2
C0068895	TUC Roadway Refurb 2025		0.0
C0069829	TUC0 - Relay Room Fire Suppression		0.0
C0052237	TUC1 ACW Strainer Replacement		0.0
C0068910	TUC1 Stack Refurb 2025		0.0
C0051841	TUC1 Turbine Generator Fire		0.0
C0069589	TUC3 - Oil Burner Front Valve Repla		0.0
C0069080	TUC3 Control Valve Replacements 25		0.0
C0061523	TRE6 PA Flow Measurement (3 of 4)		0.0
C0068891	TRE - Common Piping Replace 2025		0.0
C0068664	TRE5 U&U Precip Refurbishment		0.0
C0080189	TRE5 5-6 U&U FW Heater Refurb		0.0
C0080193	TRE6 PE FAC		0.0
C0080195	TRE5 UU 5-1 Polisher Changeout		0.0
C0080197	TRE5 U&U 5-1 BFP Motor Refurb		0.1

C0073948	TRE5 U&U Jan Boiler Tube Replace	0.0
C0080219	Deep Brook Spillway & Intake Refurb	0.0
C0080223	511N-T1 Trans Upgr Toney River Off	0.0
C0080325	TUC0 - Sodium Bisulphate Dosing	0.0
C0061244	POA Boiler Coal Chute Improvement	- 0.0
C0067946	POA Limestone Cyclone Relining	- 0.0
C0067951	POA SH1 Refurbishment	- 0.1
C0068027	POA Turbine Valves Refurbishment	0.0
C0068028	POA Arrowhead Refurbishment	0.0
C0068049	POA Condenser Water Box Relining	0.1
C0068050	POA Water Treatment Valve Overhaul	0.0
C0068343	POA Coal Transformer Cable Replace	0.0
C0068790	POA VFD Upgrades	0.0
C0068808	POA LS Piping Replacement	0.0
C0068035	POA Expansion Joint Refurbishment	0.0
C0067944	POA 8th Stage Blade Row Replacement	0.0
H001-405FP	HYD RUF1 Turbine Bearing Refurb	0.0
C0068208	LIN1 Boiler Refurbishment	0.1
C0068227	LIN1 Turbine MSV Refurbishment	0.0
C0073869	19W-311 Argyle Road Shift and Bridg	0.0
C0051597	LIN TG Lagging/Bearing Sprink Upgr	0.0
C0068448	LIN1 TG Column Protection 2025	0.0
C0068961	2025 PCB Subst Sampling and Replace	0.0
C0074630	Glance Bay Reliability Work	0.0
C0074452	L6552 - 124C TOA Grid Modernization	- 0.2
C0075128	PTMT Inhaul Wiper Deflection U&U	- 0.0
C0035610	Dec 19 2025 Level 3 - Distribution	0.1
C0080140	TUC3 Boiler Tube Leak JUL25	0.0
52248	POT Boiler Gas Temp Monitors	0.0
C0068899	TUC3 Boiler Refurb 2025	-
C0082446	Cogswell Duct Bank Replacement	0.0
C0064344	Dec 19 2025 Level 3 - Transmission	0.0
C0043992	POA UU Coal Amenities Building	0.0
C0052498	POA Cell Capping 2023	0.0
C0061023	2024 EHV Breaker Replacements	0.0
C0043010	2022 2023 Wood Pole Retreatment Prg	- 0.0
C0061286	IT - Enterprise Vulnerability Manag	- 0.0
C0063409	ICP Rail 8th Street Crossing	- 0.0
C0070046	PTMT Southeast Embankment Refurb	0.0
C0051416	PTMT Pier Subsurface Inspection	0.0
C0073768	TUC Tank1 Withdrawal Heater Refurb	- 0.0
C0069069	TUC1 BFP Instrument Panel Upgr	0.0
C0080003	IT - Capital Planning - PowerPlan	- 0.0
C0080131	LIN UU NERC Upgrades 2025	0.0

C0080136	Engine 191-443 HPC Blade Repl	0.0
C0061846	BGT Tank 1 Refurb	0.0
C0069030	TUC Wind Proof Person Doors	0.0
C0069150	TUC1 Lube Oil & Seal Oil Backwash	0.0
C0069027	TUC1 Motor Protection Relay Replace	0.0
C0069014	TUC3 EW Polished Resin Replace 25	0.0
C0053696	ECC Wind Integration Project	- 0.0
C0068806	POA Toshiba Run Up Upgrade	0.0
C0081905	LIN1 UU Boiler Tube Refurb Jan 2026	0.0
C0082267	TUC2 North BFP Motor Refurb 2025	0.0
C0081805	POA UU Boiler Return Leg Refurb	0.0
C0082273	TUC3 South BFP Motor Refurb 2025	0.0
C0069035	TUC1 Condenser Outlet Pipe Refurb	0.0
C0069006	TUC1 CEP Refurb 2025	0.0
C0068906	TUC6 Boiler Feed Pump Refurb 2025	0.0
C0069078	TUC3 CW Piping Inspection PE	0.0
C0069065	TUC1 CW Piping Refurbishment 2025	0.0
C0068888	TUC3 Continuous Ash Hauling System	0.0
C0069066	TUC1 Control Valve Replacements 25	0.0
C0081666	HYD Fundy Hydro Condition Assessmen	0.0
C0082281	POA UU FAC HEP Refurb 2025	0.0
C0061004	POA Turbine Insulation Rebuild	0.0
C0068882	TUC1 Generator Refurbishment	0.0
C0082271	TRE5 - U&U 5-4 Mill Refurbishment	0.0
C0080258	62N-T1 Transformer Replacement	0.0
C0082327	POA UU Acid Systems Refurb 2025	0.0
C0082329	POA UU Front Wall Feeder Ref 2025	0.0
C0082331	POA UU Vortex Finder Repl 2025	0.0
C0082332	POA UU Reheat Tube Refurb 2025	0.1
C0082381	POT - SD UU PCB Lighting Removal	0.0
C0082382	POT - SD UU Grizzly Replacment & As	0.0
C0082387	PHB-SD UU HEP Refurbishment 2025	0.1
C0082407	POT- SD UU Water Wall Tube Replacem	0.0
C0082425	POT - SD UU Air Heater Ductwork Ref	0.0
C0082445	PHB - SD UU Precip Duct Work Refurb	0.1
C0069109	POT - Silica Meter	0.0
C0068700	PHB - Air Heater Refurbishment 2025	0.3
C0068929	PHB - HVAC Refurbishment	0.0
C0068702	PHB - Trancel Screw Refurb 2025	0.1
C0068701	PHB - Precipitator Refurb 2025	0.3
C0068944	POT - Road Way Refurb 2025	0.1
C0068945	POT - Asbestos Abatement 2025	0.0
C0069087	POT - SOFA Duct Attachment Refurb	0.0
C0069129	POT - WTP Acid & Caustic Str M Repl	0.0

C0068949	POT - Steam Coil Air Heater Refurb	0.0
C0082566	103C-314 Target Equipment Replaceme	0.0
C0082345	POA UU South Cyclone Refractory Ref	0.0
C0068224	LIN1 Misc. Valve Refurbishment 2025	0.0
C0082586	87H-312 Musquodoboit Harbour Bridge	0.1
C0082589	99H-312 Farrell Street Feeder Upgra	0.1
C0082610	57S-402 Target Equipment Replacemen	0.2
C0082617	16W-301 Target Equipment Replacemen	0.0
C0082620	56N-414 Target Equipment Replacemen	0.0
C0082567	104H-421 Target Equipment Replaceme	0.1
C0082625	40H-302 Target Equipment Replacemen	0.0
C0082627	92H-331 Target Equipment Replacemen	0.0
C0082630	62H-304 Target Equipment Replacemen	0.0
C0082570	20H-301 Target Equipment Replacemen	0.0
C0082571	48H-301 Target Equipment Replacemen	0.0
C0082767	LIN UU Fly Ash Vac Pmp Replace 2025	0.0
50117-D772	Moose River-Upgrade	0.0
O0000116	West Converted Ops Projects	- 0.0
C0011261	101W Port Mersey Expansion	-
C0027162	129H Kearney Lake Substation Relo	-
C0044110	138kv Line Tap to 92V Substation	-
C0021642	13V Gulch Telecom Upgrades	-
C0046615	1H-419 Failed Cable Testing	-
C0022247	1N-Onslow 138 kV Add Second 42 MVA	-
C0010042	2019 Transmission ROW Widening 69kV	-
C0035848	2021 Distribution Inspection Progam	-
C0031283	2021 Substation Theft Prevention	-
C0049672	2022 Distribution Inspection Progra	-
C0031267	2022 Oil Containment Program	-
C0049652	2022 Transmission Inspection Progra	-
C0056721	2023 Transmission Inspection Progra	-
C0064725	2024 Manhole Cover Replacement	-
C0074143	2025 Manhole Cover Replacement	-
C0042608	2C-402 - Troy Build to Roadside	-
C0042969	59C-401 - Greenville Street Rebuild	-
C0042287	82V-403 Elmsdale River Crossing Reb	-
52261	83V-503 & 83V-504 - Bring Switches	-
C0031298	88S-T72 New Radiators	-
C0031119	96H-412-Dufferin Mines Rd Rebuild	-
C0069267	AiDash Satellite Analysis Administr	-
C0067803	AMO - CT Health Assessment	-
C0068105	AMO - Hydro EMS Automation	-
C0045432	AMO - RBI Program Management System	-
C0040566	AMO 69kV System Assessment	-

C0068406	AMO Alternate Fuel Assessments	-
C0050693	AMO Application Modernization	-
C0050692	AMO CMS T&D Expansion	-
C0031268	AMO Critical Equipment Online Mon.	-
C0065685	AMO Enhanced Substation Analytics	-
C0065731	AMO GE APM Connect Interface	-
C0061683	AMO GE APM Interface & V5 Upgrades	-
C0020883	AMO Gulch Enhanced Monitoring	-
C0011219	AMO HYD Head Gate Assessment Progra	-
C0019038	AMO Hydro Water Management	-
C0059626	AMO LIN3 Turbine Supervisory Upgrad	-
C0059627	AMO LIN4 Turbine Supervisory Upgrad	-
C0010939	AMO Network Asset Upgrades and Expa	-
C0059563	AMO Nuttby Ice Mitigation	-
C0058705	AMO PE OT Cyber Security Updates	-
C0016060	AMO PE TRE5 Outage Support	-
C0011003	AMO POA Outage Support	-
C0045850	AMO PP NERC Program Tools	-
C0020339	AMO Risk Repository Tool	-
C0064663	AMO Rounds Pro Upgrade	-
C0026723	AMO Satellite Vegetation Management	-
C0011680	AMO T&D Asset Assessments	-
C0051695	AMO Telecom AM	-
C0010943	AMO TRE6 Enhanced Monitoring	-
C0041548	AMO TUC Relay Information Managemen	-
C0051654	AMO TUC1 Major Outage Support	-
C0041487	AMO TUC2 Outage Support	-
C0063324	AMO TUC2 Turbine Stationary Compone	-
C0051653	AMO TUC6 Major Outage Support	-
C0029928	AMO Weymouth Telecom Upgrade	-
C0067899	AMO Wildfire Risk Mapping	-
C0018485	AMO Wind Asset Management	-
18622-P015-435	ANN-HYDRO-TOOLS AND EQUIPMENT	-
C0047870	ArcFM Mobile for T&D As-Builts	-
C0062843	BH Coal Clean-Up U&U	-
C0068871	BH Erosion Management	-
C0026148	Coal to Clean (ECEI)	-
C0043552	CT - Camera Replacement	-
28522-P040-393	CT - DCMS Equipment Replacement Rou	-
10634-G001-391	CT - Routine Equipment Replacements	-
C0050650	CT BGT Unit 3 Vibration Monitoring	-
C0050659	CT LM6000 Unit 4 dP Transmitters	-
C0050660	CT LM6000 Unit 5 dP Transmitters	-
C0041512	CT TUS1 Air Compressor & Dryer	-

C0050651	CT VJ Unit 1 Vibration Monitoring	-
C0050652	CT VJ Unit 2 Vibration Monitoring	-
C0041510	CT VJ2 AD/DC Fuel Pump Replacement	-
C0006178	D-84W-302 Subsea Cable Removal and	-
C0045132	ECEI - Energy Storage	-
C0053159	IT - PM Web	-
C0044391	ECEI - Transmission	-
48158-P018	Environmental Equipment Replacement	-
C0060866	Everwind 230kV Transmission Line	-
38896-P815	FAC Environment Site Assess Routine	-
C0068868	Fall River Substation Addition	-
50713-P016-393	Gas Turbine Tools & Equipment	-
C0062546	Hosting Capacity Map	-
C0057361	HYD - ANN Facility Isolation	-
48052-H745	HYD - ANN HVAC Upgrade	-
47649	HYD - Salmon Tail Dam Spillway Refu	-
49634-H778	HYD - Trout River Div. Screen Rplc	-
44978-H715	HYD - Wreck Cove Controls Upgrade	-
51772-H838	HYD Arc Flash Mitigation	-
C0048991	HYD AVO 2 Rock Stabilization	-
C0058523	HYD Mersey Draft Tube Bell Refurbis	-
C0042466	HYD STM Garage Refurbishment	-
C0055659	ICP Rail Center Fire Protection	-
44533-D505	IR 282 Cheticamp	-
C0060963	IR 597 - Mersey Wind Phase 1	-
C0070367	IR 618 NU - Goose Harbour Lake Wind	-
C0070386	IR 618 TPIF - Goose Harbour Lake Wi	-
C0065024	IR 662 - 132H Spider Lake BESS TPIF	-
C0069446	IR 668 - Weavers Mountain Wind	-
C0069535	IR 669 TPIF - Higgins Mountain Wind	-
C0070327	IR 673 NU - Benjamins Mill Wind	-
C0070328	IR 673 TPIF - Benjamins Mill Wind	-
C0073308	IR 677 TPIF - Wedgeport Wind	-
C0064883	IR 697 - 105V White Rock BESS TPIF	-
51963-P171	IT - Adept Upgrade	-
C0068720	IT - ADMS 2025 Minor Release	-
C0047280	IT - ADMS Maintenance Release 2024	-
C0042169	IT - Arc FM Designer Upgrade	-
C0067864	IT - CASB Platform Replacement	-
C0047214	IT - CIS HW Replacement/OS Upgrade	-
C0061301	IT - Cisco ACI Network Core Expansi	-
C0047301	IT - Cloud Integration Platform	-
C0054755	IT - Connect My Data (Green Button)	-
C0056461	IT - Contact Centre Cloud Migration	-

C0072648	IT - Customer Enrollment Automation	-
C0047213	IT - Customer Program - Compliance	-
C0061325	IT - Data Center Recovery for AMI	-
C0047190	IT - Drupal Upgrade	-
C0073189	IT - Employee Quick Assist Tool	-
C0061285	IT - Enterprise GRC	-
C0049619	IT - ERP Upgrade (EBS, PS, PP, OBIA	-
C0072848	IT - F5 Perpetual Licenses	-
C0047277	IT - GIS Utility Network Upgrade	-
C0049012	IT - Grid Analytics	-
C0068714	IT - Identity & Access Mang	-
C0042163	IT - iPhone/iPad Refresh	-
C0068727	IT - Lifecycle LWS Network Core	-
C0067863	IT - Managed Detect & Respo	-
C0047296	IT - Microsoft SQL Consolidation	-
C0072673	IT - NERC Physical Security Upgrade	-
C0059303	IT - Network Detect & Response	-
C0061289	IT - Network Next Generation Securi	-
C0049614	IT - Network Video Recorders	-
29114-P031-026	IT - NSPI Infrastructure Routine	-
C0068729	IT - Oracle Linux 7	-
C0047278	IT - Oracle MDM Upgrade	-
C0061284	IT - Enterprise Asset Management	-
C0069406	IT - PHP Vulnerability Fix	-
C0049615	IT - Physical Security Devices	-
C0072670	IT - Physical Security Devices	-
C0011159	IT - PI System Upgrade	-
C0047295	IT - Plant WiFi Upgrade	-
C0067703	IT - Prov Community Solar	-
C0047299	IT - Replacement of Cisco Endpoint	-
C0062043	IT - RIMS Implementation	-
C0062624	IT - Starlink Mobility Project	-
C0061323	IT - Storage Arrays	-
C0061295	IT - Switch Replacement Management	-
C0061443	IT - WAM Capital Enhancement Rout.	-
C0061345	IT - Windows 11 Version Upgrade	-
C0042153	IT - Windows Server 2012	-
C0010158	IT- Aligne Fuels	-
C0021835	IT- CIS Replacement	-
C0030987	IT- NERC CIP Environment Refresh	-
C0030991	IT- PC Refresh	-
C0022002	IT- Storm Centre Upgrade	-
C0030983	IT- User File Services Upgrade	-
C0011167	IT-Backup Infrastructure Upgrade	-

C0036392	L6001-366A Highway 102 Aerotech Con	-
51098-T952	L-6014 Shannon Park Trans Towers	-
25668-P040-301	LIN - DCMS Equipment Replacement Ro	-
10626-S001-301	LIN - Routine Equipment Replacement	-
11648-P016-301	LIN - Tools and Equipment Routine	-
C0064552	LIN PE Auxiliary Boiler Install	-
C0019519	LIN PF Line Replacement	-
33863-S005-301	LIN-Heat Rate Routine	-
18626-P015-470	MER-HYDRO-TOOLS AND EQUIPMENT	-
C0053316	Michelin Voltage Sag reduction DVR	-
C0021145	Mobile Substation Low Voltage Cable	-
C0041994	NERC CIP 2022	-
C0064583	NERC Standards Implementation	-
C0021140	98N-Stellarton Substation	-
C0011358	New Bridgewater Substation	-
C0061521	New Distribution ROW Phase 10	-
43646-S001-251	PHB - Routine Equipment Replacement	-
C0071448	PHB- SD UU Biomass Fuel Screw Refu	-
10718-S001-371	POA - Routine Equipment Replacement	-
21484-P016-371	POA - Tools and Equipment Routine	-
C0031227	POA 1B PA Fan Motor Lift Device	-
C0059422	POA FAC PE 2023	-
C0060257	POA Gates & Ladder Upgrades 2024	-
C0060258	POA Machinery Guarding 2024	-
C0063266	Porter's Lake Feeder Addition	-
14973-T018-820	PRIMARY EQUIPMENT SPARES	-
C0055940	Problem Feeder Recloser Remote Conn	-
C0042966	Problem Feeder Reliability Upgrades	-
25260-P002-820	PROV - TOOLS & EQP - SYS MAINTENANC	-
26757-P002-800	PROVINCIAL LINE TOOLS & EQUIPMENT R	-
C0042086	PTMT - MCC Computer Upgrades	-
C0070828	PTMT Shuttle Walkways Refurb U&U	-
38848-P032-032	Purchasing Equip & Warehouse Rout.	-
C0017098	RAL Generator Replacement	-
C0063243	RC Stormwater Refurbishment U&U	-
C0065085	Renewable Integration Power Site	-
C0050834	Spare EHV Breaker Replacements	-
C0041830	Spare Power Prod Unit Transformer	-
C0033505	Storm-Hardened Design Standards	-
12025-P002-752	SYDNEY REGION - TOOLS AND EQUIPMENT	-
C0065943	Synchronous Condensors (ECEI)	-
CONV-T016-820	T016-PROTECTION MOD.CC820	-
43827-T010-840	Transmission ROW Widening Routine	-
11621-P016-341	TRE - Tools and Equipment Routine	-

33869-S005-341	TRE-Heat Rate Routine	-
27856-S004-341	TRE-ROOFING ROUTINE	-
C0052538	TUC Lift Hoist Replacement U&U	-
C0052112	TUC Lower Parking Lot Refurb U&U	-
C0060556	TUC Overhead Door Refurb 2024	-
C0021608	TUC Shoreline Sheetpile Refurb	-
C0021463	TUC Turbine Bay Louvers Refurbishme	-
C0071772	TUC1 Boiler Tube Leak OCT24	-
C0021562	TUC1 CW Intake Canal Refurbishment	-
C0064424	TUC1 HEP Refurb 2023 2	-
C0053594	TUC2 Burner System Replacement (BAS	-
C0060578	TUC2 Replace Air Foils	-
C0073751	TUC5 Lube Oil Scavenge Pump Refurb	-
33871-S005-311	TUC-Heat Rate Routine	-
C0073168	Tusket Powerhouse Fish Passage	-
C0064966	Tusket Powerhouse Tidal Pool Fish P	-
C0021645	Tusket Telecom Upgrades	-
C0073129	UTVs for Hydro and Energy Delivery	-
C0041847	WIN - Nuttby Smoke Detection System	-
C0067643	WRC Center of Main Access Tunnel Ro	-
C0058942	WRC D11-2 Foundation Stabilization	-
C0032746	WRC Tunnel T-1 Remediation	-
C0031722	11S-412 Kings Road Roundabout	-
51493-D861	2018 PCB Pole Top Transformer Replc	-
C0054095	2023 Manhole Cover Replacements	-
C0050848	2023 Manhole Equipment Replacement	-
C0038727	22C-402 - Feeder Exit Replacement	-
C0039811	2C-402 - Route 19 Insulator Replace	-
C0051754	4S-332 - Charlotte St. Re-design Ph	-
C0036588	524S-311 Ben Eoin Conversion	-
C0036666	584N-301 Irwin Lake Rd Upgrades	-
C0024686	78W-301GA Eastern Points Repole	-
C0061923	81N-412G Bass River Bridge Replacem	-
C0032684	85S-401-Cape North Build to Aliant	-
C0035726	92H-331 Micou Island Rebuild	-
C0041447	AMO POT Turbine Supervisory Enhance	-
C0020644	AMO TUC3 Turbine Supervisory System	-
C0005318	D-15S-301 Target Replacement	-
C0033304	Downline Recloser Additions Part 1	-
11611-P015-405	Hydro Production Tools, Test Equip	-
C0073975	IR 671 NU - Bear Lake Wind	-
C0068718	IT - DERMS Solution Project	-
C0068719	IT - Distributed Intelligence Apps	-
C0047212	IT - MV90 Software Upgrade	-

C0021843	IT - Upgrade Oracle OBIA	-
11566-D007-732	JOINT USE CONSTRUCTION - BRIDGEWATE	-
47949-T876	L5028 Replacements and Upgrades	-
C0031064	L5054 Line Replacements and Upgrade	-
51394-SI85	LIN34 Control Panel Button Upg.	-
43648-P016-251	PHB - Tools and Equipment Routine	-
C0060254	POA Coal System Refurb. 2024	-
33865-S005-371	POA-Heat Rate Routine	-
C0063623	POT-PE FAC 2023 Rev2	-
18624-P015-450	SHH-HYDRO-TOOLS AND EQUIPMENT	-
38243-P814	Telecommunications Spares	-
C0055056	TRE- U&U Fence Repair	-
C0051337	TUC - Fire Protection Upgrades 2023	-
C0050899	TUC - Handrail Program 2023	-
11589-P016-311	TUC - Tools and Equipment Routine	-
C0051312	TUC Blowdown Pipe Concrete Trench	-
C0071548	TUC1 GSCW Motor & Pump Replace	-
C0071773	TUC2 IP Row 12-15 Blade Refurb	-
C0071490	TUC2 Precip Seal Air Htr Replace	-
C0052032	TUC3 Tie Breaker Refurb	-
C0048114	88S-301 Switchgear Replacement	-
C0040047	9H-221 Cornwall St Rebuild	-
C0068103	AMO Distribution Event Data Quality	-
C0068346	AMO Oracle to DirectLine Interface	-
C0043310	AMO Technology Environment Upgrade	-
39304-P063-863	Class 3 Work Vehicle Replacements	-
28430-P041-032	FAC - Land Acquisition Routine	-
C0036149	HYD - Hydro Protection Relay Tester	-
C0073777	IT - Complex Customer Projects	-
C0068724	IT - Safety IRD Replacement	-
C0069373	IT - VCC Payment Type for ERP	-
C0074928	Massachusetts Ave Bridges (x2) Asse	-
20624-P015-490	MER - MAINT HYDRO PRODUCTION - TOO	-
C0031050	New Spare Large Autotransformer	-
25667-P040-351	POT - DCMS Equipment Replacement Ro	-
C0030902	POT-PE Next Cell Development Bear He	-
CONV-T016-610	T016-PROTECTION MOD ContCent	-
25646-P040-311	TUC DCMS Equipment Replacement Rout	-
C0041664	TUC2 CW Pump Building Replacement	-
C0041926	AMO Distribution Program Initiative	-
48862-SG40	AMO PE Fleet RBI Prog Ph.IV-BoilerA	-
CONV-002	Conversion Project	-
C0073348	HYD WRC Surge Lake Volume Optimizat	-
C0005498	IT- Endpoint Security	-

C0068128	LIN Ash Site Winter Cover 2025	-
C0061583	LIN1 DC Seal/Lube Oil Motor Cable F	-
C0074340	PTMT Reclaim Slab Refurb U&U	-
20705-P012-411	SIS - SECURITY IMPROVEMENTS - HYDRO	-
C0067583	TUC6 Breaker Lifting Rack	-
C0058703	AMO 69kV Lightning Arrester Assessm	-
C0010947	AMO Competency Management System	-
C0024062	AMO PTMT-ICP Asset Management	-
C0032243	AMO Steam Chest Spare Std	-
C0041450	AMO Substation Equipment Transporta	-
C0011008	AMO TUC3 GEN OUTAGE SUPPORT	-
C0029688	CT - TUS - Air House Refurbishment	-
C0038127	HYD - AVO 1 Overhaul	-
51236-H821	HYD - WRC Tailrace Rock Bolting	-
O0080000	IT - Project Green	-
C0026724	LIN PE HMI Upgrade	-
52078	POA Frontwall Pipe Replacement	-
C0010371	TRE Auxiliary Boiler Installation	-
C0027942	TRE PE Ash Beneficiation Unit Site	-
20600-H001-408	TUS - HYDRO EQUIPMENT REPLACEMENTS	-
52249	POT Breaker Replacements / Upgrades	-
C0030371	TUC DCS HMI Upgrade	-
C0058543	WRC D-11 By-pass	-
C0005678	HYD Cowie Falls Power House	-
C0020333	POT - 2020 SSC refurbishment	-
C0069107	POT- Dionex Replacement	-
17821-P012-450	SHH - SECURITY IMPROVEMENTS - HYDRO	-
17820-P012-440	STM - SECURITY IMPROVEMENTS - HYDRO	-
40983-D365	70W-322 89W-301 Tie Line	-
C0080061	IT - Backup	-
17790-H001-430	LEQ - HYDRO EQUIPMENT REPLACEMENTS	-
C0033644	2021-2022 Steel Tower Life Extensio	-
C0072308	Dartmouth Substation Addition	-
C0041549	HYD - HMS Re-Babbitting Upgrade	-
C0080112	HYD BIF6 Rotor Reinsulation	-
C0080118	HYD LGB Drawdown Inspections	-
C0067443	HYD LGB Wall Bushing Replacement	-
C0058503	HYD MER LLF Crane Column Refurbishm	-
45812-H005-450	HYD Oil Release Risk Assessment SHH	-
C0080059	IT - Adept	-
CONV-P001-036	P001-DIST PROP IMPR Suppl Serv	-
C0068767	TRE - Sootblowers 2025	-
C0068942	TRE0 4KV Breaker Replacements 2025	-
C0080191	TRE5 U&U Burner Panel Replacement	-

C0068688	TRE6 - Boiler Valve Refurb 2025	-
C0071988	2025 Recloser Capital Spares	-
C0068467	AMO Transmission Risk Profiling	-
C0067895	AMO TUC1 Turbine Supervisory Upgrad	-
C0067897	AMO Vegetation Condition Integratio	-
C0041514	CT BGT Fuel Piping / Cable Bridges	-
C0041508	CT LM6000 TUC 5 Generator Borescope	-
28648-D116	Distribution Replacement Engineerin	-
48011-T886	Donkin Mine Reopen	-
C0052598	ICP Rail Car Refurbishment 2023	-
C0052599	ICP Rail System Refurbishment 2023	-
44535-D506	IR #256 Spiddle Hill	-
44531-D503	IR #398 Dunvegan	-
47151-D636	IR 308 Avondale	-
46931-D623	IR 384 Porters Lake	-
C0068611	LIN E Ramp Refurbishment 2025	-
C0059163	LIN1 UU Gen Stator Rewedge 2023	-
C0071228	LM6000 Accelerometer Replacement	-
C0059464	PHB - UU Bark Pad Asphalt Repairs	-
C0051414	PTMT-Conveyor System Refurbishment	-
43324-T782	Replace L6513 / Upgrade Line Termin	-
C0080092	Stillwater Lake Substation Addition	-
C0013058	T-L5039-TIR Hwy 102-103 Rebuild	-
C0063543	WRC Penstock Mucking Tunnel Rock Bo	-
C0070426	2025 Downline Recloser Additions	-
20601-H001-420	AVO - HYDRO EQUIPMENT REPLACEMENTS	-
C0080252	ECC Renewable Dispatch Data	-
C0080221	HYD BIF Powerhouse Leak Refurb	-
H005-405FP	HYD HOB Cooling Coil	-
C0080228	HYD HOB Stator Refurbishment	-
C0080230	HYD TUS 3 Stator Refurbishment	-
C0042166	IT - Data Loss Prevention Platform	-
C0080601	IT - Tech Enablement Oversight	-
C0080170	IT - Vulnerability Mgmt Platform	-
C0068237	LIN1 GSCW Piping Refurb 2025	-
C0041892	New Distribution ROW Phase 7	-
C0064023	RC Boiler Burner #2 Refurb	-
25626-P040-341	TRE DCMS Equipment Replacement Rout	-
C0047930	WIN - DIG Collector Circuit Switch	-
17835-H001-480	WRC -HYDRO EQUIPMENT REPLACEMENTS	-
C0071989	2025 Voltage Regulator Cap Spares	-
C0082305	65N-T1 River Hebert Stepdown Transf	-
C0075751	AM0 GE APM Accelerator Implementati	-
C0082609	AMO - Major Capital Project Deliver	-

C0082470	AMO - Value of Lost Load Survey	-
C0064345	Dec 4 & 5 2025 Level 3 - Substation	-
C0081985	Dynamic Voltage Restorer DVR 4	-
50654-H793	HYD - TID Lighting Replacement	-
C0019199	HYD - TUS Crane Refurbishment	-
H006-405FP	HYD DEB Actuator Displays x2	-
C0062944	HYD GIS MacMillan Gatehouse Brake R	-
C0072930	HYD GUL Plant Penstock Refurb	-
C0082269	IT - Self Serve BI & Analytics Rest	-
C0082135	IT - Virtual Wiring Inspection Port	-
C0081965	IT- Lifecycle Project Portfolio Mgt	-
C0068203	LIN Turbine Lube Oil Dehydr Replace	-
C0081885	LIN4 UU A BFP Refurbishment 2025	-
20612-H001-490	MER - MAINT HYDRO EQUIPMENT REPLACE	-
C0082428	POT - SD UU Boiler Feed Pump Casing	-
C0082386	POT-SD UU HEP Refurbishment 2025	-
23511-D018-800	Primary Equipment Spares - Distribu	-
C0068656	TRE - Aux Lube Oil Pump Overhaul	-
C0068670	TRE5 - 5C Conveyor	-
C0073930	TRE5 U&U 5-1 BFP Seals Replace	-
C0074339	TRE5 U&U Condenser Inlet Pipe Refur	-
C0061350	TRE6 - 6B Battery Bank Replacement	-
C0068690	TRE6 Stack Expansion Duct Refurb	-
C0051174	TUC3 Condenser Waterbox Refurb 2023	-
D010-840	D010 Provincial Distribution ROW	-
CONV-005	Conversion project	-
P062-863	Work Vehicle Replacements	-
C0080597	DirectLine Planning Enhancement	-
C0065686	AMO Enhanced Substation Analytics	-
C0053815	ECEI - Energy Storage	-
C0053818	ECEI - Energy Storage	-
C0080048	IT - Recovery Program Office	-
C0080024	IT - Distribution Grid Control & Op	-
C0058443	IT - Contact Centre Cloud Migration	-
C0080014	IT - AMI - HES	-
C0071850	IT - Oracle MDM Upgrade	-
C0080008	IT - Payroll (Peoplesoft)	-
C0080038	IT - Middleware	-
C0080042	IT - Data	-
C0080040	IT - Network	-
C0080044	IT - PKI	-
C0064093	91H-T11 Transformer Replacement	-
P031-026	IT - NSPI Infrastructure Routine	-
C0080032	IT - OT Hardening	-

C0080034	IT - Compute	-
C0073169	Tusket Powerhouse Fish Passage	-
C0071368	New Distribution ROW Phase 10	-
C0068697	L6038 Realignment	-
C0032824	2020 RTU Deployment Project	-
C0035349	Broadband Internet to Rural NS	-
C0035391	Bell - Broadband Internet Phase 2	-
C0046533	HYD - FAR Spillway Culvert Replacem	-
C0047090	WIN - DIG Hights Brook Crossing Re	-
C0053674	ECEI - Transmission	-
C0065526	ICP Lighting Upgrades 2024	-
C0070246	HYD - Routine Equipment Replacement	-
C0072070	57C-426H-Stillwater Phase Extension	-
C0072208	652V-212 Kentville Conversion	-
C0075369	IT - Complex Customer Projects	-
D005-623	Sack. Depot - Replace Det. Plant	-
D005-722	Northeast - Replace Deteriorated Pl	-
D005-735	Replace Deteriorated Plant - Coldbr	-
D005-752	Sydney Region - Replace Deteriorate	-
D006-623	Sack. Depot - Regulatory Replacemen	-
D007-800	D007 Contractual Replacemens (Joint	-
D061-623	New Customers - Residential CEN	-
D061-722	New Customers - Residential NE	-
D061-735	New Customers - Residential West	-
D061-752	New Customers - Residential East	-
D062-623	New Customers - Commercial CEN	-
D062-752	New Customers - Commercial East	-
P016-371	POA - Tools and Equipment Routine	-
T011-820	PROVINCIAL - PLANNED TRANS LINE REP	-
C0049553	IT - AMI Head-End System Upgrade	-
C0070450	IT - Identity & Access Mang	-
C0065563	PTMT Conveyor Refurbishment Phase 2	-
C0064444	POT- Polisher Valves Soloenoid Pan	-
C0064785	POT-WTP MCC Upgrade	-
C0065004	POT - Turbine Valves Refurbishment	-
C0073588	POT - Miscellaneous Valve / Compone	-
C0074334	POT - Breaker Replacements / Upgrad	-
S001-351	POT - Routine Equipment Replacement	-
C0074338	POT-CW Pump House Refurbishment	-
P016-351	POT - Tools and Equipment Routine	-
S004-351	POT-ROOFING ROUTINE	-
C0062384	PTMT E-Crane Stabilization	-
C0058799	POT - Sternson Carbon filter replac	-
C0065293	POT - Overhead Door Replacement	-

C0066708	POT - South Boiler Feed Pump Refurb	-
C0066943	POT - Conveyor & Fuel Handling Refu	-
C0075853	POT - Boiler Refurbishment 2025	-
C0066444	POT - Boiler Refurbishment 2024	-
C0015412	HYD-Roofing Routine	-
C0015841	West High Priority FI	-
C0015842	Deteriorated Make Ready	-
C0018979	D-Cogswell HRM Redevelopment Progra	-
C0027342	HYD WRC Tailrace Rock Bolting Ph2	-
C0037446	POT - Turbine Generator Fire Protec	-
C0039967	2021 Substation Theft Prevention	-
C0040426	ECC Optimization Tools Project	-
C0052352	TUC2 - HP/IP Turbine Refurb 2024	-
C0065651	TUC - DCS / HMI Network 2023	-
C0067069	2024 Manhole Automatic Pumps	-
C0067116	TRE5 - 5-2 CW Pump Refurbishment	-
C0067165	TUC1 South BFP & Motor Refurb 2024	-
C0067284	TUC Wharf Access Bridge Replacement	-
C0069326	TUC WTP Tank 3 Cation Vessel Replac	-
C0070626	HYD - Routine Equipment Replacement	-
C0073088	2024 Substation Fence Upgrades	-
C0073808	TUC Concrete Floor Refurb	-
C0073908	HYD - Routine Equipment Replacement	-
C0073950	TRE5 U&U Jan Boiler Tube Replace	-
C0074512	TRE - Facility Refurbishment	-
C0074571	TUC6 4160v/600v Motor Refurb 2025	-
C0074650	TUC2 HEP Refurb 2025	-
C0074653	TUC2 CW Expansion Joint Replac 2025	-
C0074769	TUC2 Control Valve Repalcements	-
C0074789	TUC2 - Oil Burner Front Valve Repla	-
C0075328	TRE5 - IP-LP Turbine Refurbishment	-
C0075358	LIN2 UU FAC Refurbishment 2025	-
C0075613	TUC1 LPT Last Stage Blade Refurb	-
C0075710	TRE6 - Waterwall Replacement	-
C0075770	TUC1 FAC Refurb 2025	-
C0075772	TUC1 HEP Refurb 2025	-
C0076154	TUC1 Boiler Refurbishment 2025	-
C0076192	TUC HVAC Refurb 2025	-
C0076354	TUC6 CW Pump Refurb 2025	-
C0076533	BGT4 Engine P686621 Case Refurb	-
C0076551	TRE5 Baghouse Filter Replaceme	-
C0080151	TUC1 HP Turbine Vibration Refurb	-
C0080164	TUC3 Boiler Refurb 2025	-
D004-735	New Customer Replacements - Western	-

D007-735	Joint Use Construction- Coldbrook B	-
D008-735	West - Col Capital Storm Routine	-
D055-735	Planned D055 For Western Region - 2	-
D062-735	New Customers - Commercial West	-
D549	West Unplanned Deteriorated Replace	-
D559	Street Light & Service Removals	-
P001-032	FAC - Property Improvements	-
P040-311	TUC DCMS Equipment Replacement Rout	-
S001-311	TUC - Routine Equipment Replacement	-
S004-311	TUC-ROOFING ROUTINE	-
S005-311	TUC-Heat Rate Routine	-
S005-351	POT-Heat Rate Routine	-
T003-820	PROVINCIAL-TRANS SUBSTATION PRIMARY	-
C0014060	Wind - Routine Equipment Replacemen	-
C0046477	CT VJ2 - Replace Generator Assembly	-
C0051273	HYD - Gulch Overhaul	-
C0068872	BH Erosion Management	-
C0073770	TUC Handrail Program 2025	-
C0074288	TUC1 Stack Protective Envelope	-
C0074292	TUC2 Stack Protective Envelope	-
C0074309	TUC 3 Stack Protective Envelope	-
C0074477	TUC3 Electric Actuators 2025	-
C0074629	TUC1 Boiler Burner Frnt Replacement	-
C0075229	TUC2 CW Inlet Screen Refurb	-
C0080128	LIN4 Condensate Extraction Pump Ref	-
C0080132	LIN UU NERC Upgrades 2025	-
C0080156	TUC Wind Proof Person Doors	-
C0080161	TUC1 Stack Refurb 2025	-
C0080166	TUC3 CW Inlet Screen Refurb	-
C0080545	SCR Rail Gauge Refurb U&U	-
C0082227	LIN1 UU Boiler Tube Refurb 2025	-
C0082286	LIN1 UU SCC Chain Replacement 2025	-
C0082367	TUC1 Condenser Outlet Pipe Refurb	-
C0082368	TUC1 CEP Refurb 2025	-
C0082371	TUC1 CW Piping Refurbishment 2025	-
C0082385	TUC1 Generator Refurbishment	-
C0082572	POT - SD UU PCB Lighting Removal	-
C0082573	POT - SD UU Grizzly Replacment & As	-
C0082576	POT- SD UU Water Wall Tube Replacem	-
C0082577	POT - SD UU Air Heater Ductwork Ref	-
C0082578	POT - SD UU Boiler Feed Pump Casing	-
C0082613	POT - Asbestos Abatement 2025	-
C0082614	POT - SOFA Duct Attachment Refurb	-
C0003758	P002-722 - NORTHEAST TOOLS	-

C0020942	Substation Replacement of Grounds	-
C0023144	HYD WRC LEM Unit Rehabilitation	-
C0036589	HYD 4th Lake Switchgear MCC Replace	-
C0046592	2022-2023 Transmission Switch & B	-
C0049613	TUC3 Aux CW Oil Detection	-
C0052322	TUC Oil Pumphouse PLC Upgrade	-
C0052360	TUC2 - MCC Refurbishments 2023	-
C0056623	HYD - COW 11 Overhaul	-
C0065068	IR 662 - 132H Spider Lake BESS TPIF	-
C0065444	TUC1 AVR Replacement	-
C0065606	2024 2025 Sacrificial Anode Install	-
C0066668	POA LP HIP Turbine Refurb	-
C0066688	TUC1 Misc Valve Replacement 2024	-
C0068695	L7022 Replacements and Upgrades	-
C0068948	TRE - Nitrogen Generator	-
C0070728	IR 673 TPIF - Benjamins Mill Wind	-
C0073632	POA Facilities/Security upgr. 2025	-
C0073958	LIN Grating Refurbishment 2025	-
C0074388	TUC1 4160V Relay Data Acquisition	-
C0080158	TUC1 ACW Strainer Replacement	-
C0080177	TRE - Aux Lube Oil Pump Overhaul	-
C0080573	POA 8th Stage Blade Row Replacement	-
C0082548	POA UU Vortex Finder Repl 2025	-
P002-623	SACK. DEPOT - TOOLS & EQUIPMENT	-
P002-742	Tools And Equipment - West	-
P016-393	Gas Turbine Tools & Equipment	-
S001-251	PHB - Routine Equipment Replacement	-
C0023143	HYD WRC LEM Unit Rehabilitation	-
C0044493	New 138KV-25KV Substation Stellarto	-
C0056460	HYD - Routine Equipment Replacement	-
C0061628	83V L5017 and L5046 Rebuild Tap	-
C0064092	10V-T1 Transformer Replacement	-
C0066623	RTU Replacements Program Phase 6	-
C0070967	HYD - Routine Equipment Replacement	-
C0073969	LIN TWW Piping Replacement 2025	-
C0074948	2025 PCB Poletop Sampling and Repla	-
C0076151	CT VJ2 Free Turbine Full Refurbishm	-
C0076191	TUC1 Cond Up Inlet Piping Replace	-
C0076644	Unspecified	-
C0070048	L5027B Replacements and Upgrades	-
C0080144	Tuc3 HEP Refurb 2025	-
C0080148	TUC3 Precip Refurb 2025	-
C0076252	Directline Planning Enhancement	-

2025 Depreciation Expense	Capital Recovery			
	2025 Depreciation & Accretion Expense	(Accumulated Depreciation)	Cost of Removal	Accretion Expense
Distribution Plant	88.9	72.6	14.9	1.3
Gas Turbine Generation Plant	5.7	5.1	0.1	0.4
General Plant	57.9	58.9	(1.0)	-
Hydro Generation Plant	15.4	13.5	0.4	1.4
Solar Generation Plant	0.1	0.1	-	-
Steam Generation Plant	76.2	72.2	0.9	3.2
Transmission Plant	33.4	26.5	4.9	2.1
Wind Generation Plant	12.6	12.6	0.0	-
Total	290.1	261.5	20.1	8.4

(\$ Millions)	Deferred Accretion in		Portion of Accretion	Portion of Accretion	Deferred
	Accumulated Depreciation- Dec	Accretion	Expense to ARO	Expense to	Accretion in
	31, 2024 (A)	Expense- 2024	Liability	Accumulated	Depreciation Dec
				Depreciation (B)	31, 2023** (A+B)
Steam Plants	12.4	3.2	(4.0)	(0.8)	11.6
Hydro Plants	5.9	1.4	(2.0)	(0.6)	5.3
Gas Turbine	0.8	0.4	(0.4)	0.1	0.9
Wind Generation	7.5	-	(0.8)	(0.8)	6.7
PCB Oil ARO	(18.9)	3.4	(0.1)	3.3	(15.6)
Total	7.7	8.4	(7.3)	1.2	8.9

**2025 Annual Financial Statements Attachment 15.1 has been
filed electronically.**

**2025 Annual Financial Statements Attachment 15.2 has been
filed electronically.**

**2025 Annual Financial Statements Attachment 15.3 has been
filed electronically.**

2025 Annual Financial Statements Attachment 16.1 has been removed due to confidentiality.

Year	Regulated Net Income	Earnings Above Approved ROE Range (\$M)	Application of Amounts		
			Section 21 Amortization ¹	FAM	Fixed Cost Deferral
2006	107.4	-	-	-	-
2007	103.0	-	-	-	-
2008	109.6	-	-	-	-
2009	111.8	4.5	4.5	-	-
2010 ²	126.8	24.8	10.3	-	-
2011 ³	131.3	0.1	0.1	14.5	-
2012	130.7	7.9	7.9	-	-
2013	132.2	-	(3.4)	-	-
2014	133.2	40.2	(17.3)	38.2	2.0
2015	139.2	26.4	(2.1)	26.4	-
2016	138.6	4.4	-	4.4	-
2017	136.5	18.4	-	18.4	-
2018	139.5	3.1	-	3.1	-
2019 ⁶	149.8	0.7	-	0.7	-
2020 ⁷	132.9	-	-	-	-
2021	152.0	-	-	-	-
2022	149.1	-	-	-	-
2023	155.4	-	-	-	-
2024	179.5	-	-	-	-
2025	164.6	-	-	-	-

¹ The Section 21 mechanism allowed NS Power to accelerate amortization of the deferred pre-2003 tax liability, reducing amortization expense in future years. Section 21 amortization was broken down in AAA1 (the amount of amortization equal to net earnings above the approved ROE range) and AAA2 (the amount of amortization that represents the reduction in net earnings that falls within NSPI's ROE band). The amounts included in this column above relate to AAA1 as AAA2 was not related to amounts above the approved ROE range. In the absence of the Section 21 accelerated amortization, earnings above NS Power's approved ROE range for the years 2014 and 2015 would have been lower.

² Of the \$24.8M earnings above NS Power's approved ROE range in 2010, \$10.3M was expensed as accelerated amortization under the section 21 mechanism. The remaining \$14.5M was tax benefits related to renewable energy projects, which was deferred in 2010 and applied to the FAM balance in 2011.

³ As per Section 14 of the Electricity Plan Implementation (2015) Act, where Nova Scotia Power's regulated rate of return on equity exceeds the range approved by the Board for the calendar years 2015, 2016, 2017, 2018 and 2019, any amount that exceeds that range is deemed to be an over recovery of fuel costs.

⁴ Regulated Earnings in 2006-2008 and 2021-2025 were below the top of the approved ROE range.

⁵ Earnings above the approved ROE range in the above table excludes tax benefits associated with the South Canoe and Sable wind projects that have been applied to the FAM as directed by the Electricity Plan Implementation (2015) Act.

⁶ In 2019, earnings above the approved ROE range exclude \$2.1M in additional LRT revenue pertaining to prior periods applied to the FAM balance as directed by the NSUARB.

⁷ Regulated Earnings in 2020 were below the bottom of the approved ROE range. However, \$1.7M in additional LRT revenue pertaining to prior periods was applied to the FAM balance in 2020, as directed by the NSUARB.

2025 Annual Financial Statements Attachment 16.3 has been removed due to confidentiality.

2025 Annual Financial Statements Attachment 16.4 has been removed due to confidentiality.