



Massachusetts Electric Company

Financial Statements

For the years ended March 31, 2026, 2025, and 2024

MASSACHUSETTS ELECTRIC COMPANY

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
Massachusetts Electric Company

Opinion

We have audited the financial statements of Massachusetts Electric Company (the "Company"), which comprise the balance sheets as of March 31, 2026 and 2025, and the related statements of operations, cash flows and changes in shareholders' equity for each of the three years in the period ended March 31, 2026, and the related notes to the financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of March 31, 2026 and 2025, and the results of its operations and its cash flows for each of the three years in the period ended March 31, 2026 in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the 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 absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. 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. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- 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. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Deloitte & Touche LLP

June 17, 2026

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF OPERATIONS
(in thousands of dollars)

	Years Ended March 31,		
	2026	2025	2024
Operating revenues	\$ 3,041,840	\$ 2,896,809	\$ 2,700,872
Operating expenses:			
Purchased electricity	521,636	585,070	559,832
Operations and maintenance	1,994,073	1,796,524	1,675,119
Depreciation and amortization	220,188	201,443	182,813
Other taxes	125,150	113,595	62,712
Total operating expenses	2,861,047	2,696,632	2,480,476
Operating income	180,793	200,177	220,396
Other income and (deductions):			
Interest on long-term debt	(100,197)	(100,210)	(78,937)
Other interest, including affiliate interest, net	(5,158)	(873)	(3,563)
Other income, net	108,560	126,860	57,149
Total other income (deductions), net	3,205	25,777	(25,351)
Income before income taxes	183,998	225,954	195,045
Income tax expense	38,106	50,590	47,078
Net income	\$ 145,892	\$ 175,364	\$ 147,967

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31,		
	2026	2025	2024
Operating activities:			
Net income	\$ 145,892	\$ 175,364	\$ 147,967
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	220,188	201,443	182,813
Regulatory amortizations	15,768	17,137	14,791
Deferred income tax (benefit) expense	(39,445)	16,788	76,411
Bad debt expense	83,925	45,894	50,870
Allowance for equity funds used during construction	(8,302)	(12,791)	(1,837)
Pension and postretirement benefits	(43,424)	(24,807)	(13,638)
Other non-cash items	1,929	3,385	616
Pension and postretirement benefit contributions, net	(111)	(15,221)	2,501
Environmental remediation payments	(2,906)	(1,992)	(7,323)
Changes in operating assets and liabilities:			
Accounts receivable and unbilled revenues, net	10,746	(172,543)	(72,316)
Accounts receivable from/payable to affiliates, net	(217,300)	4,847	75,850
Inventory	(10,889)	8,904	(34,942)
Regulatory assets and liabilities (current), net	3,703	13,913	(26,103)
Regulatory assets and liabilities (non-current), net	291,375	(11,073)	(175,857)
Derivative instruments	(45,474)	-	-
Prepaid and accrued taxes, net	54,157	62,744	76,026
Accounts payable and other liabilities	70,722	134,818	(56,557)
Renewable energy certificate obligations, net	(5,621)	(18,915)	(31,195)
Other, net	(9,615)	(5,925)	(1,749)
Net cash provided by operating activities	<u>515,318</u>	<u>421,970</u>	<u>206,328</u>
Investing activities:			
Capital expenditures	(831,336)	(590,645)	(508,686)
Cost of removal	(39,415)	(37,162)	(32,547)
Proceeds from sale of assets	2,908	5,749	-
Intercompany money pool	19,912	233,010	(252,922)
Other, net	-	-	261
Net cash used in investing activities	<u>(847,931)</u>	<u>(389,048)</u>	<u>(793,894)</u>
Financing activities:			
Preferred stock dividends	(100)	(100)	(75)
Issuance of long-term debt	-	-	400,000
Payment of debt issuance costs	-	-	(3,000)
Intercompany money pool	321,778	-	(66,546)
Equity infusion from Parent	-	-	250,000
Net cash provided by (used in) financing activities	<u>321,678</u>	<u>(100)</u>	<u>580,379</u>
Net increase (decrease) in cash, cash equivalents, restricted cash, and special deposits	(10,935)	32,822	(7,187)
Cash, cash equivalents, restricted cash, and special deposits, beginning of year	63,669	30,847	38,034
Cash, cash equivalents, restricted cash, and special deposits, end of year	<u>\$ 52,734</u>	<u>\$ 63,669</u>	<u>\$ 30,847</u>
Supplemental disclosures:			
Interest paid, net of amounts capitalized	\$ (97,171)	\$ (93,571)	\$ (76,021)
Income taxes refunded (paid), net	(20,072)	30,715	97,897
Significant non-cash items:			
Capital-related accruals included in accounts payable	32,430	20,921	14,130
Parent tax loss allocation	14,221	-	-
Right-of-use ("ROU") assets obtained in exchange for new operating lease liabilities	36,382	21,181	21,559
Asset retirement obligation - revisions to present value	9,997	-	-

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

MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2026	2025
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 23,066	\$ 35,688
Restricted cash and special deposits	29,668	27,981
Accounts receivable, net	686,275	700,716
Accounts receivable from affiliates	271,476	25,443
Intercompany money pool asset	-	19,912
Unbilled revenues, net	104,687	117,796
Inventory	143,215	147,389
Regulatory assets	268,688	224,840
Other, net	3,206	70,283
Total current assets	1,530,281	1,370,048
Property, plant, and equipment, net	6,076,643	5,351,252
Non-current assets:		
Regulatory assets	1,168,761	1,151,737
Goodwill	1,008,244	1,008,244
Postretirement benefits asset	136,235	92,542
Other	92,762	18,463
Total non-current assets	2,406,002	2,270,986
Total assets	\$ 10,012,926	\$ 8,992,286

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

MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2026	2025
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable and other	\$ 685,187	\$ 621,971
Accounts payable to affiliates	256,127	227,394
Intercompany money pool liability	321,778	-
Customer deposits	10,588	10,890
Interest accrued	25,983	25,990
Regulatory liabilities	52,597	5,046
Renewable energy certificate obligations	114,652	135,336
Payroll and benefits accruals	35,518	31,301
Environmental remediation costs	8,431	6,278
Distributed generation advances	61,526	56,733
Other	173,679	127,354
Total current liabilities	1,746,066	1,248,293
Non-current liabilities:		
Regulatory liabilities	1,288,888	939,144
Deferred income tax liabilities, net	687,241	712,500
Environmental remediation costs	72,328	68,731
Other	150,579	116,620
Total non-current liabilities	2,199,036	1,836,995
Commitments and contingencies (Note 14)		
Capitalization:		
Shareholders' equity	3,879,034	3,719,006
Long-term debt	2,188,790	2,187,992
Total capitalization	6,067,824	5,906,998
Total liabilities and capitalization	\$ 10,012,926	\$ 8,992,286

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands of dollars)

	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)			Retained Earnings	Total
				Unrealized Gain on Available- For-Sale Securities	Pension and Other Postretirement Benefits	Total Accumulated Other Comprehensive Income (Loss)		
Balance as of March 31, 2023	\$ 59,953	\$ 2,259	\$ 1,871,699	\$ 252	\$ (350)	\$ (98)	\$ 1,214,680	\$ 3,148,493
Net income	-	-	-	-	-	-	147,967	147,967
Other comprehensive income:								
Change in pension and other postretirement obligations, net of \$91 tax expense	-	-	-	-	240	240	-	240
Total comprehensive income	-	-	-	-	240	240	-	148,207
Equity infusion from Parent	-	-	250,000	-	-	-	-	250,000
Preferred stock dividends	-	-	-	-	-	-	(75)	(75)
Implementation of ASC 326, net of \$1,014 tax benefit	-	-	-	-	-	-	(2,696)	(2,696)
Balance as of March 31, 2024	\$ 59,953	\$ 2,259	\$ 2,121,699	\$ 252	\$ (110)	\$ 142	\$ 1,359,876	\$ 3,543,929
Net income	-	-	-	-	-	-	175,364	175,364
Other comprehensive income (loss):								
Change in pension and other postretirement obligations, net of \$70 tax benefit	-	-	-	-	(187)	(187)	-	(187)
Total comprehensive income	-	-	-	-	(187)	(187)	-	175,177
Preferred stock dividends	-	-	-	-	-	-	(100)	(100)
Balance as of March 31, 2025	\$ 59,953	\$ 2,259	\$ 2,121,699	\$ 252	\$ (297)	\$ (45)	\$ 1,535,140	\$ 3,719,006
Net income	-	-	-	-	-	-	145,892	145,892
Other comprehensive income:								
Change in pension and other postretirement obligations, net of \$6 tax expense	-	-	-	-	15	15	-	15
Total comprehensive income	-	-	-	-	15	15	-	145,907
Parent tax loss allocation	-	-	14,221	-	-	-	-	14,221
Preferred stock dividends	-	-	-	-	-	-	(100)	(100)
Balance as of March 31, 2026	\$ 59,953	\$ 2,259	\$ 2,135,920	\$ 252	\$ (282)	\$ (30)	\$ 1,680,932	\$ 3,879,034

The Company had 2,398,111 shares of common stock authorized, issued, and outstanding, with a par value of \$25 per share, and 22,585 shares of cumulative preferred stock authorized, issued, and outstanding, with a par value of \$100 per share, as of March 31, 2026, 2025 and 2024.

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

**MASSACHUSETTS ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS**

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Massachusetts Electric Company (“the Company”) is an electric retail distribution company providing electric service to approximately 1.4 million customers in Massachusetts. The properties of the Company consist principally of substations and distribution lines interconnected with transmission and other facilities of New England Power Company (“NEP”), an affiliated entity.

The Company is a wholly owned subsidiary of National Grid USA (“NGUSA” or the “Parent”), a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution, and sale of both natural gas and electricity. NGUSA is a direct wholly owned subsidiary of National Grid North America Inc. (“NGNA”) and an indirect wholly owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

Pursuant to a settlement agreement associated with NGUSA’s purchase of Nantucket Electric Company (“Nantucket Electric”) in 1996, which was approved by the Massachusetts Department of Public Utilities (“DPU”), the Company and its affiliate, Nantucket Electric, are considered as one regulated entity for the purpose of recovering costs and establishing rates assessed to customers, with the exception of the recovery of Nantucket Electric’s investment in two undersea electric cables. In the recovery of certain regulatory assets, funding of the recovery is from the customers of both companies. The mechanism by which recovery is ultimately achieved, however, is through a single regulatory asset recorded on the balance sheet of the Company. Nantucket Electric’s share of these costs and recoveries is reflected through a return on equity (“ROE”) mechanism between the Company and Nantucket Electric, as discussed in Note 16, “Related Party Transactions”.

The accompanying financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (“U.S. GAAP”), including the accounting principles for rate-regulated entities. The financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The Company has evaluated subsequent events and transactions through June 17, 2026, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the financial statements as of and for the year ended March 31, 2026, with the exception of items otherwise disclosed in these financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to U.S. GAAP, the Company must make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities included in the financial statements. Such estimates and assumptions are reflected in the accompanying financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission (“FERC”) and the DPU regulate the rates the Company charges its customers. In certain cases, the rate actions of the FERC and the DPU can result in accounting that differs from that of non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. In accordance with Accounting Standards Codification (“ASC”) 980, “*Regulated Operations*”, regulatory assets and liabilities are reflected on the balance sheet consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Revenues are recognized for electric distribution services billed on a monthly cycle basis, together with unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the reporting period. See Note 3, "Revenue", for additional details.

Income Taxes

Federal and state income taxes have been computed utilizing the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized for temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred tax assets and liabilities are measured using enacted statutory tax rates expected to be in effect when differences are expected to be reversed. Deferred income taxes also reflect the tax effect of net operating losses, capital losses, and general business credit carryforwards. The Company assesses the available positive and negative evidence to estimate whether enough future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that the Company will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount.

The effects of tax positions are recognized in the financial statements when it is more likely than not that the position taken, or expected to be taken, in a tax return will be sustained upon examination by taxing authorities based on the technical merits of the position. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property.

NGNA files consolidated federal tax returns including all the activities of its subsidiaries. Each subsidiary determines its tax provision based on the separate return method, modified by a benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. The benefit of consolidated tax losses and credits are allocated to the NGNA subsidiaries giving rise to such benefits in determining each subsidiary's tax expense in the year that the loss or credit arises. In a year that a consolidated loss or credit carryforward is utilized, the tax benefit utilized in consolidation is paid proportionately to the subsidiaries that gave rise to the benefit regardless of whether that subsidiary would have utilized the benefit. The tax sharing agreement also requires NGNA to allocate its parent tax losses, excluding deductions from acquisition indebtedness to each subsidiary in the consolidated federal tax return with taxable income. The allocation of NGNA's parent tax losses to its subsidiaries is accounted for as a capital contribution and is performed in conjunction with the annual intercompany cash settlement process following the filing of the federal tax return. The Corporate Alternative Minimum Tax ("CAMT") is allocated based on the ratio of separate company CAMT to total consolidated NGNA CAMT.

Other Taxes

The Company collects taxes and fees from customers, such as sales taxes, other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues).

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Cash and cash equivalents are carried at cost, which approximates fair value.

Restricted Cash and Special Deposits

Restricted cash and special deposits consist of collateral paid to the Independent System Operator – New England ("ISO-NE") in connection with the ISO-NE's market participant financial assurance requirement.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to reflect certain financial assets (including accounts receivable, unbilled accrued revenues, and other current assets) net of expected credit losses, at estimated net realizable value.

The allowance for doubtful accounts is determined based on a variety of factors, including, for each type of receivable, applying an estimated reserve percentage to each aging category, which takes into account historical collections, write-off experience, and management's assessment of collectability from customers, as appropriate. Management continuously assesses the collectability of receivables and adjusts estimates accordingly if circumstances change and such adjustments are reasonable and supportable based on actual experience, current conditions, and forward-looking information as well as future expectations. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated, and when such balances are deemed to be uncollectible.

Inventory

Inventory is composed of materials and supplies as well as purchased renewable energy certificates ("RECs").

Materials and supplies are stated at weighted average cost and are expensed or capitalized as used. Inventory is written down to the lower of cost or net realizable value. There were no significant write-offs of obsolete inventory for the years ended March 31, 2026, 2025, and 2024.

RECs are stated at cost and are used to measure compliance with state renewable energy standards. The Company is required to comply with the Renewable Energy Portfolio Standard, which requires retail sellers of electricity to obtain a certain minimum percentage or amount of their power supply from renewable energy sources. RECs support new renewable generation resources and are held primarily to be utilized in fulfillment of the Company's compliance obligations under the Renewable Energy Portfolio Standard.

The Company had materials and supplies of \$78.2 million and \$67.3 million and purchased RECs of \$65.0 million and \$80.1 million as of March 31, 2026 and 2025, respectively.

Power Purchase Agreements

The Company and its affiliate, Nantucket Electric, enter into power purchase agreements ("PPAs") to procure electricity to serve its electric service customers. The Company first evaluates whether such agreements contain a lease. In performing this evaluation, the Company considers whether the terms of the PPA provide the Company with the right to direct use of the generating facility and if the Company has the right to obtain substantially all of the economic benefits derived from use of the facility. In determining whether the Company has the right to direct use of the facility, the Company will consider which rights have the most significant impact on the economic benefits to be derived from the asset; for example, dispatch rights or the right to be involved in the facility's design. If the PPA is determined to contain a lease, the Company assesses whether it should be classified as a finance lease or an operating lease.

If the PPA does not contain a lease, the Company assesses whether the contract is a derivative or includes one or more embedded derivatives. In making this determination, the Company assesses whether the PPA includes a notional amount or payment provision through the contract's delivery requirements or terms of default. If the PPA is a derivative or contains one or more embedded derivatives, the Company will assess whether the requirements for election of the normal purchases and normal sales scope exception are met. If the requirements for the election are not met or the election is not made, the Company reports the derivative at fair value on the consolidated balance sheet. If the election is made, the Company accounts for the PPA as an executory contract whereby costs are recognized as electricity is purchased. If the contract does not contain a lease and is not a derivative, the Company accounts for the PPA as an executory contract.

The Company also assesses whether the PPA is a variable interest in a variable interest entity ("VIE"). In determining whether the PPA is a variable interest, the Company assesses whether the contract absorbs certain risks, such as commodity price risk,

that the VIE was designed to pass on to its interest holders. If the PPA is determined to be a variable interest in a VIE, the Company determines whether it is the primary beneficiary.

Distributed Generation Advances

Distributed generation refers to electricity that is generated from sources located near the point of use instead of centralized generation sources. Customers wishing to connect a power-generating facility to the Company's electric power system are responsible for all review and study costs, interconnection equipment costs, and system modification costs reasonably incurred by the Company that are attributable to the proposed interconnection project. The Company bills customers for the costs that it expects to incur, and customers must pay these costs before the Company performs any work. The Company records such customer contributions that have not yet been spent within Distributed Generation Advances on the balance sheet.

Derivative Instruments

The Company enters into contracts to purchase and procure energy and energy-related products for their customers, which are subject to price volatility, through the use of derivative and non-derivative contracts. The costs associated with supplying energy to customers are recoverable from customers in future rates.

Regulatory assets or regulatory liabilities are recorded to defer the recognition of unrealized losses or gains on derivative instruments, respectively. The gains or losses on the settlement of these contracts are recognized as purchased electricity on the statements of operations and then refunded to, or collected from, customers consistent with regulatory requirements. The mark to market unrealized losses or gains of these derivative contracts are deferred as regulatory assets if the derivative is a liability or as regulatory liabilities if the derivative is an asset.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, but rather to record and present the fair value of the derivative instruments on a gross basis, with any related cash collateral recorded within restricted cash and special deposits on the balance sheet.

Fair Value Measurements

The Company measures securities, derivative instruments, and pension and postretirement benefit other than pension ("PBOP") plan assets at fair value. Fair value is the price that would be received to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;
- Level 2: inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data;
- Level 3: unobservable inputs, such as internally developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs; and
- Not categorized: Investments in funds that meet certain conditions of ASC 820 are not required to be categorized within the fair value hierarchy. These investments are typically in commingled funds or limited partnerships that are not publicly traded and have ongoing subscription and redemption activity. As a practical expedient, the fair value of these investments is the Net Asset Value ("NAV") per fund share.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost. The capitalized cost of additions to property, plant, and equipment includes costs such as direct materials, labor and benefits, and an allowance for funds used during construction (“AFUDC”). The cost of repairs and maintenance is charged to expense, and the cost of renewals and betterments that extend the useful life of property, plant, and equipment is capitalized.

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the FERC and the DPU. The average composite rates for the years ended March 31, 2026, 2025, and 2024 were 3.3%, 3.2%, and 3.1%, respectively.

Depreciation expense includes a component for the estimated cost of removal (“COR”), which is recovered through rates charged to customers. Any difference in cumulative costs recovered and costs incurred is recognized as a regulatory liability or regulatory asset, as appropriate. When property, plant, and equipment is retired, the original cost, less salvage, is charged to accumulated depreciation, and the related COR is removed from the associated regulatory liability.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the debt and equity costs of financing the construction of new property, plant, and equipment. The equity component of AFUDC is reported in the accompanying statements of operations as non-cash income in other income, net. The debt component of AFUDC is reported as a non-cash offset to other interest, including affiliate interest, net. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base. The Company recorded AFUDC related to equity of \$8.3 million, \$12.8 million, and \$1.8 million, and AFUDC related to debt of \$10.9 million, \$6.0 million, and \$9.2 million, for the years ended March 31, 2026, 2025, and 2024, respectively. The average AFUDC rates for the years ended March 31, 2026, 2025, and 2024 were 5.6%, 7.3%, and 5.7%, respectively.

Impairment of Long-Lived Assets

The Company tests long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount of the asset (or asset group) may not be recoverable. If such an event is identified, the recoverability of an asset group is determined by comparing its carrying value to the estimated undiscounted cash flows the asset group is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of carrying value over the estimated fair value. The Company also considers whether there have been any abandonments or disallowances of recently completed plant, such that guidance provided by ASC 980 on regulated property, plant and equipment may apply. For the years ended March 31, 2026, 2025, and 2024, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on October 1, or more frequently if events occur or circumstances exist that indicate it is more likely than not that the fair value of the Company is below its carrying amount. The goodwill impairment test requires a recoverability test based on the comparison of the Company’s estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, the Company is required to recognize an impairment charge for such excess, limited to the carrying amount of goodwill.

The Company applies two valuation methodologies to estimate its fair value, discounted projected future net cash flows and market-based multiples, commonly referred to as the income approach and market approach, respectively. Key assumptions include, but are not limited to, estimated future cash flows, an appropriate discount rate, and multiples of earnings. In estimating future cash flows, the Company incorporates current market information and historical factors. The determination of fair value incorporates significant unobservable inputs, requiring the Company to make significant judgments, whereby actual results may differ from assumed and estimated amounts. For the year ended March 31, 2026, the Company applied a 50/50

weighting for each valuation methodology, as it believes that each approach provides equally valuable and reliable information regarding the Company's estimated fair value.

The Company performed its latest annual goodwill impairment test as of October 1, 2025, at which time the Company's estimated fair value exceeded the carrying value. The Company did not recognize any goodwill impairment during the years ended March 31, 2026, 2025, or 2024.

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant and equipment primarily associated with the Company's distribution facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, if the fair value can be reasonably estimated. In the period in which new asset retirement obligations, or changes to the timing or amount of existing retirement obligations are recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the asset retirement obligation is accreted to its present value.

The Company applies regulatory accounting guidance, and both the depreciation and accretion costs associated with asset retirement obligation are recorded as increases to regulatory assets on the balance sheet. These regulatory assets represent timing differences between the recognition of costs in accordance with U.S. GAAP and costs recovered through the ratemaking process.

The Company does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain distribution and other assets cannot currently be estimated, and no amounts are recognized on the financial statements.

Employee Benefits

The Company participates with other NGUSA subsidiaries in defined benefit pension plans and PBOP plans for its employees, administered by NGUSA. The Company recognizes its portion of the pension and PBOP plans' funded status on the balance sheet as a net liability or asset. The cost of providing these plans is recovered through rates; therefore, the net funded status is partially offset by a regulatory asset or liability. The pension and PBOP plans' assets are commingled and allocated to measure and record pension and PBOP funded status at each year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Leases

The Company has various operating leases, primarily related to buildings, land, and fleet vehicles. Right-of-use ("ROU") assets consist of the lease liability together with any payments made to the lessor prior to commencement of the lease (less any lease incentives) and any initial direct costs. ROU assets are amortized over the lease term. Lease liabilities are recognized based on the present value of the lease payments over the lease term at the commencement date. For any leases that do not provide an implicit rate, the Company uses an estimate of its collateralized incremental borrowing rate, based on the information available at the commencement date, to determine the present value of future payments. In measuring lease liabilities, the Company excludes variable lease payments, other than those that depend on an index or a rate, or those that are, in substance, fixed payments, and includes lease payments made at or before the commencement date. Variable lease payments were not material for the years ended March 31, 2026, 2025, and 2024.

The Company recognizes lease expense based on a pattern that conforms to the regulatory ratemaking treatment.

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Income Taxes (Topic 740): Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, “*Income Taxes (Topic 740): Improvements to Income Tax Disclosures*” which improves the income tax disclosures by requiring disaggregated information about a reporting entity’s effective tax rate reconciliation as well as information on income taxes paid. The Company retrospectively adopted this standard for the annual period ended March 31, 2026. The adoption enhanced income taxes disclosures, which are included in Note 12, “Income Taxes”.

Accounting Guidance Not Yet Adopted

Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses

In July 2025, the FASB issued ASU 2025-05, “*Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses for Accounts Receivable and Contract Assets*”. The ASU provides a practical expedient for developing reasonable and supportable forecasts when estimating expected credit losses on accounts receivable and contract assets. If elected, entities may assume that current conditions as of the balance sheet date will remain unchanged over the remaining life of the asset.

The ASU is effective for the Company for the annual period beginning April 1, 2026. The Company has not yet determined whether it will elect the practical expedient for estimating credit losses and is currently assessing the application of the new guidance; however, it does not expect the adoption to have a material impact on its current allowance for expected credit losses.

Interim Reporting: Narrow-Scope Improvements (Topic 270)

In December 2025, the FASB issued ASU No. 2025-11, “*Interim Reporting (Topic 270): Narrow-Scope Improvements*”, which improves the navigability of the required interim disclosures and clarifies the related requirements and the applicability of Topic 270.

The Company is required to adopt this standard for interim reporting periods within annual periods beginning April 1, 2029, with early adoption permitted. The guidance may be applied either on a prospective or retrospective basis. The Company is currently assessing the application of the new guidance but does not expect the adoption to have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Environmental Credits and Environmental Credit Obligations (Topic 818)

In May 2026, the FASB issued ASU No. 2026-02, “*Environmental Credits and Environmental Credit Obligations (Topic 818)*”, which establishes guidance on the recognition, measurement, presentation, and disclosure of environmental credits and environmental credit obligations.

The guidance applies to environmental credits acquired, generated, or received, and requires entities to account for such credits based on their intended use, which affects both recognition and subsequent measurement. It also clarifies when environmental credit obligation liabilities arise under regulatory compliance programs and how those obligations should be measured, including consideration of the environmental credits expected to be used to settle the obligation.

The Company is required to adopt this standard for annual periods beginning April 1, 2028, and for interim periods within those annual periods, with early adoption permitted. The guidance should be applied on a retrospective basis through a cumulative-effect adjustment to opening retained earnings. The Company is currently assessing the application of the new

guidance to determine the impact on the presentation, results of operations, cash flows, and financial position of the Company.

3. REVENUE

The following table presents, for the years ended March 31, 2026, 2025, and 2024, revenue from contracts with customers, as well as additional revenue from sources other than contracts with customers, disaggregated by major source:

	Years Ended March 31,		
	2026	2025	2024
		<i>(in thousands of dollars)</i>	
Revenue from contracts with customers:			
Electric services	\$ 2,905,486	\$ 2,950,243	\$ 2,720,894
Total revenue from contracts with customers	2,905,486	2,950,243	2,720,894
Revenue from alternative revenue programs	103,231	(90,460)	(50,452)
Other revenue	33,123	37,026	30,430
Total operating revenues	\$ 3,041,840	\$ 2,896,809	\$ 2,700,872

Electric services: The Company owns, maintains, and operates an electric distribution network in upstate Massachusetts. Distribution revenues are primarily from the sale of electricity and related services to retail customers. Distribution sales are regulated by the DPU, which is responsible for determining the prices and other terms of services as part of the ratemaking process. The arrangement where a utility provides a service to a customer in exchange for a price approved by a regulator is referred to as a tariff sales contract. Electric services revenues are derived from the regulated sale and distribution of electricity to residential, commercial, and industrial customers within the Company's service territory under the tariff rates. The tariff rates approved by the regulator are designed to recover the costs incurred by the Company for the products and services provided, along with a return on investment.

The performance obligation related to these sales is to provide electricity to the customers on demand. The electricity supplied under the tariff represents a single performance obligation, as it is a series of distinct goods or services that are substantially the same. The performance obligation is satisfied over time because the customer simultaneously receives and consumes the electricity as the Company provides these services. The Company records revenues based upon the approved tariff rate and the volume delivered to the customers, which corresponds with the amount the Company has the right to invoice.

This revenue also includes estimated unbilled amounts, which represent the estimated amounts due from retail customers for electricity provided to customers by the Company but not yet billed. Unbilled revenues are determined by taking estimated unbilled sales volumes for the respective customer classes and then applying the applicable tariff rate to those volumes. Actual amounts billed to customers when the meter readings occur may be different from the estimated amounts. Certain customers have the option to obtain electricity from other suppliers. In those circumstances, revenue is only recognized for providing delivery of the commodity to the customer.

Additionally, the Company owns an electric transmission system in Massachusetts. Transmission systems generally include overhead lines, underground cables, and substations connecting generation and interconnectors to the distribution system. The Company's transmission services are regulated by both the ISO-NE and the FERC. Additionally, the Company makes available its transmission facilities to NEP for operation and control pursuant to an integrated facilities agreement. See Note 16, "Related Party Transactions", for additional details. Transmission revenues arise under tariff/rate agreements and are collected primarily from the Company's distribution customers.

Revenue from alternative revenue programs: The Company records revenues in accordance with accounting principles for rate-regulated operations for arrangements between the Company and the regulator, which are not accounted for as contracts with customers. These primarily include programs that qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the Company to adjust rates in the future, in response to past activities or completed events. The Company's electric

distribution rates have a revenue decoupling mechanism (“RDM”) which allows for annual adjustments to the Company’s delivery rates as a result of the reconciliation between allowed revenue and billed revenue.

In addition, the Company has other ARPs related to the achievement of certain objectives, demand-side management initiatives, and certain other rate-making mechanisms. The Company recognizes revenues from ARPs with a corresponding offset to a regulatory asset or liability account when the regulatory specified events or conditions have been met, when the amounts are determinable, and are probable of recovery (or payment) through future rate adjustments within 24 months from the end of the annual reporting period.

Other revenue: Includes lease income and other transactions that are not considered contracts with customers.

4. ALLOWANCE FOR DOUBTFUL ACCOUNTS

Receivables are recorded at amortized cost, net of a credit loss allowance for doubtful accounts. The allowance primarily relates to trade receivables from utility customers (both billed and unbilled), as well as amounts receivable from various other counterparties such as governmental agencies, municipalities, and other utilities. The Company recorded bad debt expense of \$91.3 million, \$54.7 million, and \$61.2 million for the years ended March 31, 2026, 2025, and 2024, respectively, within operations and maintenance expense in the accompanying statements of operations.

The activity in the allowance for doubtful accounts for the years ended March 31, 2026 and 2025 was as follows:

	Years Ended March 31,					
	2026			2025		
	<i>(in thousands of dollars)</i>					
	Utility Accounts Receivable	Non-utility Accounts Receivable	Total Allowance	Utility Accounts Receivable	Non-utility Accounts Receivable	Total Allowance
Beginning balance	\$ 198,299	\$ 5,493	\$ 203,792	\$ 215,700	\$ 4,691	\$ 220,391
Credit loss expense	91,649	3,312	94,961	71,930	1,070	73,000
Write-offs	(119,732)	(2,590)	(122,322)	(108,503)	(2,555)	(111,058)
Recoveries	20,354	2,340	22,694	19,172	2,287	21,459
Ending balance	\$ 190,570	\$ 8,555	\$ 199,125	\$ 198,299	\$ 5,493	\$ 203,792

5. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded on the balance sheets:

	March 31,	
	2026	2025
<i>(in thousands of dollars)</i>		
Regulatory assets		
Current:		
Rate adjustment mechanisms	\$ 56,476	\$ 76,250
Renewable energy certificates	49,638	55,258
Residential assistance adjustment factor	111,964	7,927
Revenue decoupling mechanism	-	15,888
Transmission service	47,131	65,527
Other	3,479	3,990
Total	268,688	224,840
Non-current:		
AMI/AMR recovery	50,875	32,380
Capital tracker	54,580	15,168
Electric vehicle incentive program	59,945	35,020
Environmental response costs	78,749	73,034
Exogenous events	121,555	172,018
Grid modernization	58,725	42,034
Net metering deferral	292,481	321,842
Postretirement benefits	130,030	90,013
Rate adjustment mechanisms	43,991	41,302
Storm costs	229,031	265,550
Other	48,799	63,376
Total	1,168,761	1,151,737
Regulatory liabilities		
Current:		
Rate adjustment mechanisms	6,883	5,046
Revenue decoupling mechanism	45,714	-
Total	52,597	5,046
Non-current:		
Cost of removal	415,470	388,577
Derivative instruments	45,474	-
Energy efficiency	69,204	160,337
Environmental response costs	22,381	19,505
Postretirement benefits	125,901	78,221
Regulatory tax liability, net	257,423	271,603
ROE Complaint	343,173	-
Other	9,862	20,901
Total	\$ 1,288,888	\$ 939,144

Regulatory assets associated with future financial obligations that were deferred in accordance with orders issued by the DPU do not earn a return until such time a cash outlay has been made.

The Company recovers carrying charges related to regulatory assets where there has been a cash outlay. These carrying charges include an interest component, recognized as a component of regulatory assets, associated with the portion of the regulatory assets deemed to be financed with debt. These carrying charges also include an equity return component, which is an allowance for earnings on shareholders' investment. This equity return component will be recovered through future rates but is not recognized for financial reporting purposes. The equity return component not recognized in the financial statements as of March 31, 2026 and 2025 was \$80.8 million and \$28.9 million, respectively.

Advanced metering infrastructure ("AMI") / Automatic meter reading ("AMR") recovery: The regulatory asset tracks the incremental expenses and cost recovery related to the Company's AMI recovery, approved by the DPU in D.P.U. 21-81, and the legacy AMR meters that are now included in the Advanced Meter Infrastructure Factor ("AMIF") per the rate case order D.P.U. 23-150. The Company is allowed to recover incremental costs associated with the Company's implementation and deployment of AMI. Recovery of eligible AMI investments is limited to investments made over a five-year term during calendar years 2023 through 2027. The Company is allowed recovery of return on rate base, depreciation expense and property taxes associated with AMR legacy meters.

Capital tracker: The Infrastructure, Safety, Reliability, and Electrification ("ISRE") Program was approved by the DPU in D.P.U. 23-150. Under the mechanism, the Company is authorized to recover costs associated with the Company's implementation and deployment of its core capital investments under the program and seek cost recovery for these supporting investments through the annual ISRE factor filing.

Cost of removal: Represents cumulative removal amounts collected, but not yet spent, to dispose of property, plant, and equipment. This liability is discharged as removal costs are incurred.

Derivative instruments: This regulatory liability is associated with a PPA agreement the Company entered into with H.Q. Energy Services Inc. ("H.Q. Energy") in accordance with Massachusetts clean energy legislation and under the Massachusetts Clean Energy 83D procurement. The project became operational on January 16, 2026. Costs of this contract are recoverable from customers. The Company recognizes a derivative instrument associated with the contract, which is accounted for at fair value, with subsequent changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs. See Note 8, "Derivative Instruments", Note 9, "Fair Value Measurements" and Note 14, "Commitments and Contingencies" for additional details.

Electric vehicle incentive program: This regulatory asset represents deferred costs associated with expenses incurred by the Company under its approved Electric Vehicle Market Development Program and Cost Recovery Provisions. The Company is permitted to recover the incremental costs associated with the design, construction, funding of electric vehicle charging equipment stations, and certain program development expenses.

Energy efficiency: Represents the difference between revenue billed to customers through the Company's energy efficiency charge and the costs of the Company's energy efficiency programs, as approved by the state authorities.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs, with variances deferred for future recovery from, or return to, customers. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation costs. This regulatory balance does not earn a return.

Exogenous events: This regulatory asset represents deferred costs that qualify for exogenous cost recovery under the Company's Performance-based Ratemaking ("PBR") plan. This includes 1) exogenous property taxes, as approved per D.P.U. 23-55, resulting from the property tax valuation methodology change by the Department of Revenue; 2) exogenous storm costs where the incremental costs exceed \$30.0 million per event (provided that the combined balance of the Company's storm fund and any costs over \$30.0 million associated with such storm event exceed \$75.0 million); and 3) exogenous costs related to borderline services that neighboring utilities provide to the Company's customers and borderline services the Company provides to the neighboring utilities' customers. Effective September 30, 2025, these borderline service-related costs are no longer included in the balance, as their recovery was disallowed pursuant to an updated DPU order. See Note 6, "Rate Matters," for additional information. The property tax and borderline related events do not earn a return.

Grid modernization: Represents the deferred costs associated with the approved Grid modernization program approved per D.P.U. 15-120. Under the mechanism, the Company is allowed to recover incremental grid modernization capital investment under the program and implements a reconciling mechanism to concurrently recover capital expenditures and related incremental operation and maintenance ("O&M") costs.

Net metering deferral: Reflects the recovery mechanism for costs associated with customer-installed on-site generation facilities, including the costs of renewable generation credits. This surcharge provides the Company with a mechanism to recover such amounts.

Postretirement benefits: As a result of guidance received in the Company's most recent base distribution rate case in D.P.U. 23-150, it was determined that any differences between actual costs and amounts used to establish rates related to pension and PBOP expenses starting October 1, 2024 are no longer deferred and collected from, or refunded to, customers in subsequent periods but will now be included as a component of base rate recovery. Prior to the DPU order, the Company's unamortized non-cash accrual of net actuarial gains and losses, offset by the excess amounts received in rates over actual costs of the Company's pension and PBOP plans, were recovered from or passed back to customers in future periods. The order allowed the deferral balance as of September 30, 2024 to be deferred and collected from, or refunded to, customers in subsequent periods. These regulatory assets and liabilities do not earn a return and are excluded from the rate base.

Rate adjustment mechanisms: In addition to commodity costs, the Company is subject to a number of additional rate adjustment mechanisms, whereby an asset or liability is recognized, resulting from differences between billed revenues and the underlying cost being recovered or differences between billed revenues and targeted amounts, as approved by the DPU. The rate related regulatory assets such as long-term contracting for renewable energy recovery ("LTCRER") and unbilled revenue do not earn a return.

Regulatory tax liability, net: Represents over-recovered federal and state deferred taxes of the Company, primarily as a result of regulatory flow-through accounting treatment, state income tax rate changes, and excess federal deferred taxes as a result of the Tax Cuts and Jobs Act of 2017 ("Tax Act").

Renewable energy certificates: Represents deferred costs associated with the Company's compliance with Massachusetts' Renewable Portfolio Standards ("RPS"). The RPS legislation was established to foster the development of new renewable energy sources. The regulatory asset will be recovered over the next year. The regulatory assets do not earn a return and are excluded from the rate base.

Residential assistance adjustment factor ("RAAF"): The Company is allowed to recover the incremental costs associated with the operation of the Company's Arrearage Management Programs ("AMPs") offered to qualifying customers, along with the discount provided to customers receiving retail delivery service under Residential Low-Income Rate R-2. Pursuant to rate case order D.P.U. 23-150, on June 1, 2025, the Company replaced the flat 32% discount rate with a tiered discount rate structure, with rates ranging from 32% to 71% based on the customer's state median income and the federal poverty level. The recovery of the tiered discount program through RAAF began on March 1, 2026.

Revenue decoupling mechanism ("RDM"): As approved by the DPU, the Company has an electric RDM, which allows for an annual adjustment to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed and unbilled revenues. Any difference is recorded as a regulatory asset or regulatory liability. Only regulatory assets related to the unbilled revenues do not earn a return.

ROE Complaint: On March 19, 2026, FERC issued an order lowering NEP and the New England Transmission Owners ("NETOs")' base ROE from 10.57% to 9.57%. FERC also ordered refunds with interest for the fifteen-month period from filing of the first complaint in 2011 and for the period from October 2014 to the date of the order. The ROE Complaint represents the Regional Network Service ("RNS") /Local Network Service ("LNS") revenue requirement refund and interest estimate the Company will receive from NEP and non-affiliated NETOs, which will be refunded to customers.

Storm costs: The Company is allowed to recover qualifying storm costs from all retail delivery service customers. This balance reflects costs incurred and yet to be recovered. See Note 6, "Rate Matters", for additional information regarding the recovery of storm costs.

Transmission service: The Company arranges transmission service on behalf of its customers and bills the costs of those services to customers pursuant to the Company's Transmission Service Cost Adjustment Provision. Any over or under

recoveries of these costs are passed on to customers receiving transmission service over the subsequent year. The regulatory assets do not earn a return and are excluded from the rate base.

6. RATE MATTERS

General Rate Case

On September 30, 2024, the Company and its affiliate, Nantucket Electric, received Order D.P.U. 23-150 from the DPU on its proposed base distribution rate filing. The DPU approved a base distribution revenue increase of \$90.2 million based upon a 9.35% return on equity, and a capital structure of 52.83% equity, 47.12% long-term debt, and 0.05% preferred stock. The order includes a new ISRE mechanism that provides timely funding for growing core capital investment requirements up to a cap, a Performance-Based Ratemaking (“PBR-O”) recovery mechanism for O&M costs, and an increase in storm cost recovery. The new base distribution rates were reflected on customers’ bills effective November 1, 2024.

PBR Plan Filing

On June 13, 2025, the Company and Nantucket Electric filed their first annual PBR-O filing, pursuant to their 2023 rate case. The filing requested a performance-based rate (“PBR”) adjustment of approximately \$26.4 million, effective October 1, 2025, based on a PBR percentage of 4.70%. This amount includes \$8.7 million for recovery of ongoing borderline service costs that were not included in the Company’s cost of service. As part of the filing, the Company also sought recovery of \$19.9 million in prior period borderline service costs, treating them as an exogenous event, since these expenses had not been previously reflected in the cost of service.

On September 30, 2025, the DPU issued its order approving a total annual increase of \$17.7 million, while denying recovery of \$8.7 million in ongoing borderline service costs included in the proposed adjustment, as well as disallowance of \$19.9 million in prior period borderline costs.

Recovery of Transmission Costs

The Company’s transmission facilities are currently operated in combination with the transmission facilities of its New England affiliate, NEP, as a single integrated system, with NEP designated as the combined operator. In accordance with the provisions in the Integrated Facilities Agreement (“IFA”) between NEP and the Company, the Company is compensated for its actual monthly transmission costs, with its authorized maximum ROE of 11.74% on its transmission assets. On March 19, 2026, FERC issued an order lowering the base ROE applicable to transmission assets under the ISO-NE open access transmission tariff (“OATT”) from 10.57% to 9.57%. In accordance with the IFA provisions, the Company will submit a FERC filing to amend the authorized ROE as of March 19, 2026 to incorporate the base 9.57% ROE that FERC recently authorized for the NETOs. The Company recorded total receivables of \$343.2 million, including \$253.1 million recorded as an intercompany receivable from its affiliate, NEP, \$70.1 million recorded in accounts receivable, net, and \$20.0 million recorded in other noncurrent assets. The \$343.2 million total receivable is fully offset by a corresponding regulatory liability, which is expected to be refunded through future rate adjustments.

Grid Modernization Plan

On March 14, 2025, the Company and Nantucket Electric made its Grid Modernization Plan (“GMP”) cost recovery filing for calendar year 2024, seeking to recover \$33.9 million, including interest. On April 29, 2025, the DPU issued a preliminary ruling allowing cost recovery to begin, subject to further investigation and reconciliation.

On March 13, 2026, the Company and Nantucket Electric made its GMP cost recovery filing for calendar year 2025, seeking to recover \$56.0 million, including interest. The DPU approved the Company’s proposed factors to recover the costs, subject to further investigation and reconciliation.

Advanced Metering Infrastructure

On March 14, 2025, the Company and Nantucket Electric made their AMI cost recovery filing for calendar year 2024, seeking to recover a revenue requirement for calendar year 2024 of \$25.6 million, plus estimated interest for a total amount of \$26.6 million. On April 29, 2025, the DPU issued a preliminary ruling allowing cost recovery to begin, subject to further investigation and reconciliation.

On March 12, 2026, the DPU opened an investigation into the use of AMI interval data for ISO-NE load settlement. On April 23, 2026, the Company filed its initial comments in response to questions from the DPU, stating that its approved AMI plan does not include systems needed for ISO-NE load settlement, and approximately \$40.0 million in additional investment over seven years would be required. The Company supports AMI-based load settlement but stresses the costs are incremental and were not part of its approved AMI business case. The Company recommended third-party energy service providers—as primary beneficiaries—pay fees to offset costs rather than burdening ratepayers. Implementation will require approximately 20 months post-approval and will depend on unresolved DPU and ISO-NE guidance on data parameters. Scope changes could alter timelines and costs.

On March 13, 2026, the Company and Nantucket Electric made their AMI cost recovery filing for calendar year 2025, seeking to recover \$44.7 million, including interest. The DPU approved the Company's proposed factors to recover the costs, subject to further investigation and reconciliation.

Storm Threshold Deferral Requests

On June 14, 2024, the Company and Nantucket Electric requested approval to defer \$10.85 million of storm expenditures related to calendar year 2023 until the storm cost recovery filing is made in 2025. On February 11, 2025, the DPU permitted recovery of this amount through the Company's Storm Fund Replenishment Factor ("SFRF"), subject to a prudency review in a future proceeding.

The DPU approved the Company and Nantucket Electric's request to defer \$24.8 million of storm deductibles related to calendar years 2020 through 2022 for future recovery which was later updated to \$18.6 million. On September 30, 2024, the DPU approved the recovery of \$14.0 million through the Company's SFRF in the D.P.U. 23-150 order.

Storm Cost Recovery

On May 31, 2024, the Company and Nantucket Electric submitted a cost recovery filing to the DPU for 8 qualifying weather events which occurred between January 17, 2022 and December 22, 2022 totaling \$45.1 million in O&M costs.

On June 30, 2025, the Company and Nantucket Electric submitted a prudency review to the DPU for \$71.3 million incremental O&M associated with 14 storm fund-qualifying weather events which occurred between January 2023 and December 2023, and \$67.4 million incremental O&M associated with two exogenous events occurring in March 2023 and December 2023 that are currently recovered through the exogenous storm factor filed in the Company's 2024 PBR, D.P.U. 24-68.

On March 13, 2026, the DPU issued a final order approving the majority of O&M storm costs for the 17 qualifying storm events which occurred between September 2017 and December 2019 totaling \$85.9 million in O&M costs. On April 10, 2026, the Company filed its compliance filings pursuant to the order with revised amounts for approval of \$83.4 million. The Company is awaiting approval of these compliance filings.

Electric Sector Modernization Plan

Massachusetts climate legislation requires each electric distribution company to develop an Electric Sector Modernization Plan ("ESMP") to proactively upgrade the distribution system to help the Commonwealth realize its statewide greenhouse gas ("GHG") emissions limits and sublimits. On August 29, 2024, the DPU issued its order approving the ESMPs filed by the Company and Nantucket Electric, and the other Massachusetts electric distribution companies ("EDCs") as strategic plans (with minor modifications) for the five-year period July 1, 2025 through June 30, 2030. On June 13, 2025, the DPU issued its

order approving the EDCs' proposed interim annual reconciling cost recovery mechanism and limiting the scope of the Company's proposed ESMP investments that are eligible for cost recovery through the interim mechanism. On July 3, 2025, the DPU approved a term total expenditure cap for the Company of \$570.0 million for eligible investments.

Capital Investment Projects ("CIP")

On October 31, 2024, the DPU approved four CIPs the Company proposed under the Provisional System Planning Program ("PSPP") that the DPU established to facilitate interconnecting certain solar and energy storage system (DG) facilities to the distribution system.

On April 14, 2025, the Company submitted a new CIP proposal under the extension of the PSPP established by the ESMP order, allocating approximately \$39.1 million in costs, which will be recovered from interconnecting and distribution customers. The new CIP is still being adjudicated.

On March 13, 2026, the DPU found the Company demonstrated good cause to continue constructing all four approved CIPs with cost recovery.

Solar Phase II and III

On August 30, 2024, the Company and Nantucket Electric made a cost recovery filing for the last solar generation facility in the Solar Phase III program docketed as D.P.U. 24-129. The facility is located in Grafton, MA and went into service on June 30, 2024. The total revenue requirement requested was \$1.3 million. The remaining Phase II and Phase III solar facilities were included for recovery through base distribution rates in D.P.U. 23-150.

The Company and Nantucket Electric have filed two annual cost recoveries for the costs incurred in 2024 (D.P.U. 25-05) and 2025 (D.P.U. 26-05) that are still pending approval for (1) the 12-month revenue requirement for the facilities and (2) the reconciliation from the prior year of the thirteen Phase II and Phase III facilities' actual revenue requirement, O&M, property taxes, net proceeds from the sales of energy to ISO-NE, proceeds from the sales of renewable energy certificate, market value of REC used for RPS compliance and proceeds associated with bidding the capacity of the solar generating facilities into the ISO-NE Forward Capacity Market against billed revenue generated through the Solar Factors.

On March 17, 2025, the DPU issued its final approval on the Company's recovery of \$7.1 million in costs incurred in 2022 associated with Phase II and III Company owned solar facilities and the base distribution rate true-up, submitted in 2023 and docketed as D.P.U. 23-07.

On April 28, 2026, the DPU issued its final approval on the Company's recovery of \$5.7 million in costs incurred in 2023 associated with the Phase II and III Company owned solar facilities and the based distribution rate true-up submitted in 2024 and docketed as D.P.U. 24-02.

Electric Vehicle Program

On March 7, 2025, the Company, together with Nantucket Electric, received final approval from the DPU to recover \$5.8 million in costs associated with the Electric Vehicle ("EV") programs (Phase I, II, III) for calendar year 2023 through the EV Factor.

On May 15, 2025, the Company, together with Nantucket Electric, filed a proposal with the DPU to recover \$24.8 million in costs associated with the EV programs (Phase I, II, III) for calendar year 2024 through the EV Factor, including interest and past period under-recovery (D.P.U. 25-68). On June 30, 2025 the Department approved the proposed EV factor to take effect on July 1, 2025, subject to further investigation and reconciliation.

On December 30, 2025, the Company, together with Nantucket Electric, filed with the DPU a proposal for Phase IV EV Program with a total budget of \$193.7 million.

On May 15, 2026, the Company, together with Nantucket Electric, filed its annual filing for the recovery of \$43.0 million associated with its Phase II and III EV program. If the DPU approves, the proposed EV Factor will take effect July 1, 2026.

2025-2027 Three-Year Energy Efficiency Plan

On October 31, 2024, the three-year energy efficiency plan was filed jointly by all Program Administrators (“PAs”), which involved a nearly \$5.0 billion investment to help achieve Massachusetts’ 2030 climate goals. The Company and Nantucket Electric’s portion of the \$5.0 billion requested budget for the next three years is \$1.5 billion.

On February 28, 2025, the DPU approved the PAs three-year plans, with modifications, the most notable of which is a large reduction in budget of \$500.0 million to the residential sector, from a plan total of \$5.0 billion to \$4.5 billion. The PAs submitted their compliance filing on April 30, 2025, which reflected the \$500.0 million reduction. The Company and Nantucket Electric’s updated budget for the next three years is \$1.4 billion, inclusive of performance incentives. On February 27, 2026, the Company and Nantucket Electric submitted a petition for approval of its 2026 Energy Efficiency Reconciliation Factors (“EERFs”) for effect May 1, 2026 through April 30, 2027. The DPU approved the Company’s request on April 29, 2026.

Service Quality

On March 20, 2025, the Company filed proposals to refund \$15.1 million in penalties to customers due to service quality issues in calendar year 2023. The penalties stemmed from failure to meet metrics regarding customer complaints, Circuit Average Interruption Duration Index, and Circuit Average Interruption Frequency Index. The Company proposed to refund the penalties as a one-time credit on customer bills in May 2025 with any residual balance to be included in the Company’s RDM reconciliation. On April 18, 2025, the DPU approved the customer refund to be applied to customer bills in May 2025.

On January 12, 2026, the DPU issued its order for the Company’s annual service quality report; the DPU approved the report without penalty.

Infrastructure, Safety, Reliability, and Electrification

The Company, together with Nantucket Electric, filed its first annual ISRE filing on June 13, 2025. The filing proposed to recover \$21.7 million of incremental costs associated with the Company’s implementation and deployment of its core capital investments, including interest. On September 30, 2025, the DPU issued a Phase I Order approving the factor, pending further investigation and reconciliation. The DPU issued a final procedural schedule that sets March 31, 2026 and April 1, 2026 as hearing dates, if needed. No hearings were held, briefing was concluded on May 1, 2026.

Department of Energy Resources (“DOER”)

On March 4, 2025, the Company received a request from the DOER to credit a sum of Alternative Compliance Payments collected by the DOER to the Company’s residential customers. As of March 31, 2025, the Company recorded this as a receivable within other current assets, net and a liability within other current liabilities. The Company received \$60.1 million from the DOER on April 2, 2025, and applied a one-time \$50 credit to the bills of its residential customers.

2026 Winter Bill Relief

The DPU approved a comprehensive winter bill relief program proposed by the Company and its affiliates Nantucket Electric and Boston Gas Company. For residential electric customers, the program will apply a 25% reduction to total bills during the February and March 2026 billing cycles. This relief program is structured as a combination of state funding and deferred cost recovery, with approximately \$94.0 million (equivalent to about 15% bill reduction) funded directly by the Commonwealth of Massachusetts. On March 16, 2026, the Company and Nantucket Electric filed for recovery of the cost for the approximate remaining 10% of relief. The DPU approved the request on April 28, 2026, without modification, allowing the Company to recover the costs from customers between May 1, 2026, and December 31, 2026.

7. PROPERTY, PLANT, AND EQUIPMENT

The following table summarizes property, plant, and equipment at cost and operating leases ROU assets, along with accumulated depreciation and amortization:

	March 31,	
	2026	2025
	<i>(in thousands of dollars)</i>	
Plant and machinery	\$ 7,093,670	\$ 6,441,987
Land and buildings	364,296	300,436
Assets in construction	523,412	475,613
Operating leases ROU assets	159,182	135,290
Total property, plant, and equipment	8,140,560	7,353,326
Accumulated depreciation and amortization	(1,994,233)	(1,936,974)
Accumulated amortization – Operating lease ROU assets	(69,684)	(65,100)
Property, plant, and equipment, net	\$ 6,076,643	\$ 5,351,252

8. DERIVATIVE INSTRUMENTS

In accordance with Massachusetts clean energy legislation and under the Massachusetts Clean Energy 83D procurement, in June 2018, the Company entered into a 20-year power purchase agreement for the purchase of renewable hydroelectric energy and renewable energy attributes from Hydro-Québec. The agreement requires the Company to purchase 498 MW of energy per hour through January 2046. Upon commercial operation, the PPA is accounted for as a non-derivative host contract for the purchase of renewable energy attributes and an embedded derivative for the purchase of the hydroelectric energy. The embedded derivative is bifurcated and recognized as a derivative instrument at fair value. The derivative does not qualify for the normal purchase and normal sales exception. Derivative contracts that are not designated as normal are recorded at fair value as derivative assets or liabilities on the balance sheets.

The following tables reflect the gross and net amounts of the Company's derivative assets and liabilities, categorized by risk type, as of March 31, 2026:

	March 31, 2026				
	Gross amounts of recognized assets (liabilities)	Gross amount offset in the balance sheet	Net amount of assets (liabilities) presented in the balance sheet	Gross amount not offset on the balance sheet	Net amount
	A	B	C=A+B	D	E=C-D
	<i>(in thousands of dollars)</i>				
ASSETS:					
Other current assets, net					
Electric contracts	\$ 2,393	\$ -	\$ 2,393	\$ -	\$ 2,393
Other non-current assets					
Electric contracts	43,081	\$ -	43,081	\$ -	43,081
Total	\$ 45,474	\$ -	\$ 45,474	\$ -	\$ 45,474
LIABILITIES:					
Net assets	\$ -	\$ -	\$ -	\$ -	\$ -
	\$ 45,474	\$ -	\$ 45,474	\$ -	\$ 45,474

The contract was recorded as derivative assets and were offset by regulatory liabilities, reflecting full recovery from the Company's customers. As a result, the changes in fair value of those contracts had no impact in the accompanying statements of operations. All of the Company's derivative instruments are subject to rate recovery as of March 31, 2026.

9. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2026:

March 31, 2026				
	Level 1	Level 2	Level 3	Total
	<i>(in thousands of dollars)</i>			
Assets:				
Derivative instruments				
Electric contracts	\$ -	\$ -	\$ 45,474	\$ 45,474
Total	-	-	45,474	45,474
Liabilities:				
Derivative instruments				
Electric contracts	\$ -	\$ -	-	-
Total	-	-	-	-
Net assets	\$ -	\$ -	\$ 45,474	\$ 45,474

Derivative instruments:

The Company's Level 3 fair value derivative instrument consists of the embedded energy derivative associated with the renewable electric purchase contract from Hydro Quebec. When bifurcating the embedded energy derivative, the Company applied an allocation methodology to separate the fair market value of the embedded energy derivative from the non-derivative host contract. The fair value of the embedded energy derivative is estimated using an internally developed discounted cash flow model that compares forward market pricing to the adjusted fixed price for the energy component of the PPA.

The valuation includes both observable inputs (peak and off-peak forward electricity prices) and unobservable inputs (adjustments to peak and off-peak forward electricity prices to estimate pricing extending into unobservable periods through the term of the PPA). Where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This also includes assumptions about market risks, such as liquidity, volatility, and contract duration. Unobservable inputs have been determined to be significant to the overall inputs, and the entire valuation is categorized in Level 3 of the fair value hierarchy. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates. As of March 31, 2026, Level 3 unobservable inputs utilized in the valuation of the Company's power purchase agreement include energy prices ranging from \$28.00 per MWh through \$174.15 per MWh, or a weighted average of \$61.04 per MWh, over the contractual period of 2026 through 2046.

The following table presents changes in the Level 3 category of derivative assets measured at fair value for the year ended March 31, 2026.

March 31, 2026	
<i>(in thousands of dollars)</i>	
Beginning balance	\$ -
Net unrealized gains	100,014
Settlements	(54,540)
Ending balance	\$ 45,474

10. EMPLOYEE BENEFITS

The Company participates with other NGUSA subsidiaries in qualified and non-qualified non-contributory defined benefit pension plans (the “Pension Plans”) and PBOP plans (the “PBOP Plans,” together with the Pension Plans, the “Plans”), covering substantially all employees.

Plan assets are maintained for all of NGUSA and its subsidiaries in commingled trusts. In respect of cost determination, plan assets are allocated to the Company based on its proportionate share of the projected benefit obligations. The Plans’ costs are first directly charged to the Company based on the Company’s employees that participate in the Plans. Costs associated with affiliated service companies’ employees are then allocated as part of the labor burden for work performed on the Company’s behalf. As a result of guidance received in the Company’s most recent base distribution rate case in D.P.U. 23-150, it was determined that any differences between actual costs and amounts used to establish rates related to pension and PBOP expenses starting October 1, 2024 are no longer deferred and collected from, or refunded to, customers in subsequent periods but will now be included as a component of base rate recovery. Prior to the DPU order, the Company’s unamortized non-cash accrual of net actuarial gains and losses, offset by the excess amounts received in rates over actual costs of the Company’s pension and PBOP plans, were recovered from or passed back to customers in future periods. The order allowed the deferral balance as of September 30, 2024 to be deferred and collected from, or refunded to, customers in subsequent periods. Pension and PBOP service costs are included within operations and maintenance expense, and non-service costs are included within other income, net in the accompanying statements of operations. Non-service costs contain components for interest cost, expected return on assets, amortization of actuarial gain/loss and settlement charges. Portions of the net periodic benefit costs disclosed below have been capitalized as a component of property, plant, and equipment, net.

Pension Plans

The Qualified Pension Plans are defined benefit plans which provide most union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives and for eligible participants covers compensation levels in excess of the Internal Revenue Service (“IRS”) limits. During the years ended March 31, 2026, 2025, and 2024, the Company made no contributions to the Qualified Pension Plans. The Company expects to contribute \$12.0 million to the Qualified Pension Plans during the year ending March 31, 2027.

Benefit payments to Pension Plan participants for the years ended March 31, 2026, 2025, and 2024 were approximately \$33.4 million, \$31.3 million, and \$61.4 million, respectively. Benefit payments for the year ended March 31, 2024 included payments for an annuity contract purchase.

PBOP Plans

The PBOP Plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements, and, in most cases, retirees must contribute to the cost of their coverage. During the years ended March 31, 2026, 2025, and 2024, the Company made contributions to the PBOP Plans of zero, \$15.1 million, and zero, respectively. The Company contributions for the year ended March 31, 2025 included a non-recurring contribution. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2027.

Gross benefit payments to PBOP Plan participants for the years ended March 31, 2026, 2025, and 2024 were approximately \$11.3 million, \$15.2 million, and \$14.1 million, respectively.

Net Periodic Benefit Costs

The Company’s total net periodic pension costs (benefits) for the years ended March 31, 2026, 2025, and 2024 were (\$5.3) million, (\$5.9) million, and (\$4.3) million, respectively. This included non-service pension costs (benefits) for the years ended March 31, 2026, 2025, and 2024 of (\$13.6) million, (\$15.4) million, and (\$14.6) million, respectively.

The Company's total net periodic PBOP costs (benefits) for the years ended March 31, 2026, 2025, and 2024 were (\$12.9) million, (\$6.0) million, and (\$5.0) million, respectively. This included non-service PBOP costs (benefits) for the years ended March 31, 2026, 2025, and 2024 of (\$15.9) million, (\$8.6) million, and (\$8.0) million, respectively.

Amounts Recognized in Regulatory Assets/Liabilities and Accumulated Other Comprehensive Income

The following tables summarize the Company's changes in actuarial gains/losses and prior service costs recognized in regulatory assets/liabilities and accumulated other comprehensive income ("AOCI") as of March 31, 2026, 2025, and 2024:

	Pension Plans		
	March 31,		
	2026	2025	2024
	<i>(in thousands of dollars)</i>		
Net actuarial loss (gain)	\$ 22,215	\$ 4,782	\$ (15,294)
Amortization of net actuarial loss	(24)	(33)	(40)
Amortization of prior service cost, net	-	-	(3)
Total	<u>\$ 22,191</u>	<u>\$ 4,749</u>	<u>\$ (15,337)</u>
Change in regulatory assets or liabilities	\$ 22,212	\$ 4,492	\$ (15,006)
Change in AOCI	(21)	257	(331)
Total	<u>\$ 22,191</u>	<u>\$ 4,749</u>	<u>\$ (15,337)</u>
	PBOP Plans		
	March 31,		
	2026	2025	2024
	<i>(in thousands of dollars)</i>		
Net actuarial (gain) loss	\$ (54,545)	\$ (8,614)	\$ (17,584)
Amortization of net actuarial gain	6,865	3,822	3,092
Total	<u>\$ (47,680)</u>	<u>\$ (4,792)</u>	<u>\$ (14,492)</u>
Change in regulatory assets or liabilities	\$ (47,680)	\$ (4,792)	\$ (14,492)
Total	<u>\$ (47,680)</u>	<u>\$ (4,792)</u>	<u>\$ (14,492)</u>

Amounts Recognized in Regulatory Assets/Liabilities and AOCI – not yet recognized as components of net actuarial gain/loss

The following tables summarize the Company’s amounts recognized in regulatory assets/liabilities and AOCI on the balance sheet that have not yet been recognized as components of net actuarial gain/loss as of March 31, 2026, 2025, and 2024:

	Pension Plans		
	March 31,		
	2026	2025	2024
	<i>(in thousands of dollars)</i>		
Net actuarial loss	\$ 128,033	\$ 105,842	\$ 101,093
Total	<u>\$ 128,033</u>	<u>\$ 105,842</u>	<u>\$ 101,093</u>
Included in regulatory assets	\$ 127,646	\$ 105,434	\$ 100,942
Recognized in AOCI	387	408	151
Total	<u>\$ 128,033</u>	<u>\$ 105,842</u>	<u>\$ 101,093</u>
	PBOP Plans		
	March 31,		
	2026	2025	2024
	<i>(in thousands of dollars)</i>		
Net actuarial gain	\$ (125,901)	\$ (78,221)	\$ (73,429)
Total	<u>\$ (125,901)</u>	<u>\$ (78,221)</u>	<u>\$ (73,429)</u>
Included in regulatory liabilities	\$ (125,901)	\$ (78,221)	\$ (73,429)
Total	<u>\$ (125,901)</u>	<u>\$ (78,221)</u>	<u>\$ (73,429)</u>

Reconciliation of Funded Status to Amounts Recognized on the Balance Sheet

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2026	2025	2026	2025
	<i>(in thousands of dollars)</i>			
Projected benefit obligation	\$ (624,688)	\$ (618,452)	\$ (178,869)	\$ (223,697)
Allocated fair value of assets	652,204	662,838	287,100	271,331
Funded status	<u>\$ 27,516</u>	<u>\$ 44,386</u>	<u>\$ 108,231</u>	<u>\$ 47,634</u>
Non-current assets	\$ 28,004	\$ 44,908	\$ 108,231	\$ 47,634
Non-current liabilities	(488)	(522)	-	-
Total	<u>\$ 27,516</u>	<u>\$ 44,386</u>	<u>\$ 108,231</u>	<u>\$ 47,634</u>

For the year ended March 31, 2026, the net actuarial loss for Pension was primarily driven by updated census data, partially offset by an increase in the discount rate. The net actuarial gain for PBOP was primarily driven by revisions to expected per capita claims costs, as well as statutory updates to certain Medicare programs and actual investment returns higher than expected, partially offset by slight increases to trend rates.

For the year ended March 31, 2025, the net actuarial loss for Pension was primarily driven by asset losses due to returns that were less than expected and demographic losses related to salaries higher than expected, partially offset by an increase in the discount rate. The net actuarial gain for PBOP was driven by an increase in the discount rate and favorable claims experience, partially offset by asset losses due to actual returns that were less than expected.

For the year ended March 31, 2024, the net actuarial gains for Pension was primarily driven by an increase in discount rate and slight changes in the retirement assumption tables resulting from a recent experience study, partially offset by asset losses due to returns that were less than expected. The net actuarial gains for the PBOP Plans were driven by an increase in discount rate, savings recognized from a Pharmacy Benefit Manager market check completed for the Company's contract, as well as the updated Medicare Advantage contract to reflect actual enrollment.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2026 (amounts for PBOP Plans are shown net of employer group waiver plan subsidies expected):

<i>(in thousands of dollars)</i>	Pension Plans		PBOP Plans	
Years Ending March 31,				
2027	\$	39,411	\$	11,733
2028		41,109		12,281
2029		42,484		12,710
2030		43,885		12,992
2031		44,984		13,218
2032-2036		229,904		66,321
Total	\$	441,777	\$	129,255

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	Years Ended March 31,		
	2026	2025	2024
Benefit obligations:			
Discount rate	5.60%	5.50%	5.15%
Rate of compensation increase (non-union)	4.30%	4.30%	4.30%
Rate of compensation increase (union)	4.25%	4.25%	4.25%
Weighted average cash balance interest crediting rate	5.60%	5.10%	4.47%
Net periodic benefit costs:			
Discount rate	5.50%	5.15%	4.85%
Rate of compensation increase (non-union)	4.30%	4.30%	4.30%
Rate of compensation increase (union)	4.25%	4.25%	4.25%
Expected return on plan assets	6.75%	6.75%	6.50%
Weighted average cash balance interest crediting rate	5.10%	4.40%	4.40%
	PBOP Plans		
	Years Ended March 31,		
	2026	2025	2024
Benefit obligations:			
Discount rate	5.60%	5.50%	5.15%
Net periodic benefit costs:			
Discount rate	5.50%	5.15%	4.85%
Expected return on plan assets	6.50%	6.25%-6.50%	6.25%-6.75%

The Company selects its discount rate assumption based upon rates of return on highly rated corporate bond yields in the marketplace as of each measurement date. The Company uses high quality corporate bond yields and the expected future cash flows from the Company retirement plans to determine the weighted average discount rate assumption.

The expected rate of return for various passive asset classes is based on both analysis of historical rates of return and forward-looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of the long-term assumptions. A premium is added for active management of both equity and

fixed income securities. The long-term rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in an expected return on plan assets for each plan.

Assumed Health Cost Trend Rate

	Years Ended March 31,	
	2026	2025
Health care cost trend rate assumed for next year		
Pre-65	7.00%	6.00%
Post-65	4.90%	5.00%
Prescription	8.00%	9.00%
Rate to which the cost trend is assumed to decline (ultimate)	4.50%	4.50%
Year that rate reaches ultimate trend		
Pre-65	2037	2031
Post-65	2031	2031
Prescription	2033	2033

Plan Assets

The Pension Plan is a trustee non-contributory defined benefit plan covering all eligible represented employees of the Company and eligible non-represented employees of the participating National Grid companies. The PBOP Plans are both a contributory and non-contributory, trustee, employee life insurance and medical benefit plan sponsored by NGUSA. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of NGUSA.

NGUSA, as the Plans' sponsor, manages the benefit plan investments for the exclusive purpose of providing retirement benefits to participants and beneficiaries and paying plan expenses. The benefit plans' named fiduciary is the Retirement Plans Committee ("RPC"). The RPC seeks to minimize the long-term cost of operating the Plans, with a reasonable level of risk. The investment objectives of the Plans are to maintain a level and form of assets adequate to meet benefit obligations to participants, to achieve the expected long-term total return on the Plans' assets within a prudent level of risk and maintain a level of volatility that is not expected to have a material impact on the Company's expected contributions and expenses or the Company's ability to meet plan obligations.

The RPC has established and reviews at least annually the Investment Policy Statement ("IPS"), which sets forth the guidelines for how plan assets are to be invested. The IPS contains a strategic asset allocation for each plan which is intended to meet the objectives of the Plans by diversifying its funds across asset classes, investment styles, and fund managers. An asset liability analysis typically is conducted periodically to determine whether the current strategic asset allocation continues to represent the appropriate balance of expected risk and reward for the plan to meet expected liabilities. Each study considers the investment risk of the asset allocation and determines the optimal mix of assets for the plan. The target asset allocation for fiscal year end 2026 continues to reflect the results of asset liability analyses implemented in prior years. As a result of the most recent Pension Plans asset liability analysis conducted in fiscal year 2025, the asset mix was adjusted to further reduce investment risk given the increased funded status of the Plans and to better hedge the respective plan liabilities, and no changes were made in fiscal year 2026. The most recent Non-Union PBOP Plan asset liability study was conducted in fiscal year 2024, with related asset allocation changes approved by the RPC effective in fiscal year 2024. The last Union PBOP asset liability study was conducted in fiscal year 2023, and the related asset allocation remains in effect.

Individual fund managers operate under written guidelines provided by the RPC, which cover such areas as investment objectives, performance measurement, permissible investments, investment restrictions, trading and execution, and communication and reporting requirements. National Grid management, in conjunction with a third-party investment advisor, regularly monitors, and reviews asset class performance, total fund performance, and compliance with asset allocation guidelines. This information is reported to the RPC at quarterly meetings. The RPC changes fund managers and rebalances the portfolio as appropriate.

Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments and is mainly invested in investment-grade securities. Where investments are made in non-investment grade assets, the higher volatility is carefully judged and balanced against the expected higher returns. While the majority of plan assets are invested in equities and fixed income, other asset classes are utilized to further diversify the investments. These asset classes include private equity, infrastructure, real estate, and diversified alternatives. The objective of these other investments is enhancing long-term returns while improving portfolio diversification. For the PBOP Plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after tax returns consistent with the broad asset class parameters established by the asset liability study. Investment risk and return are reviewed by the plan investment advisors, National Grid management and the RPC on a regular basis. The assets of the Plans have no significant concentration of risk in one country (other than the United States), industry or entity.

The target asset allocations for the benefit plans as of March 31, 2026 and 2025 are as follows:

	Pension Plan		Union PBOP Plans		Non-Union PBOP Plans	
	March 31,		March 31,		March 31,	
	2026	2025	2026	2025	2026	2025
Equity	5%	5%	15%	15%	70%	70%
Diversified alternatives	1%	2%	5%	5%	0%	0%
Fixed income securities	70%	70%	80%	80%	30%	30%
Private equity	13%	12%	0%	0%	0%	0%
Real estate	4%	5%	0%	0%	0%	0%
Infrastructure	7%	6%	0%	0%	0%	0%
	100%	100%	100%	100%	100%	100%

Fair Value Measurements

The following tables provide the fair value measurement amounts for the pension and PBOP assets at the trust level (includes all trusts applicable to Plans the Company participates in):

March 31, 2026				
	Level 1	Level 2	Not categorized	Total
	<i>(in thousands of dollars)</i>			
Pension assets:				
Equity	\$ -	\$ -	\$ 81,513	\$ 81,513
Diversified alternatives	-	-	18,703	18,703
Corporate bonds	-	583,841	142,103	725,944
Government securities	3,172	365,388	207,121	575,681
Private equity	-	-	237,861	237,861
Real estate	-	-	65,876	65,876
Infrastructure	-	-	120,551	120,551
Total assets	\$ 3,172	\$ 949,229	\$ 873,728	\$ 1,826,129
Pending transactions				(85,906)
Total net assets				\$ 1,740,223
PBOP assets:				
Equity	\$ 47,525	\$ -	\$ 482,385	\$ 529,910
Diversified alternatives	159,714	-	-	159,714
Corporate bonds	-	1,620,366	151,442	1,771,808
Government securities	45,396	587,519	447	633,362
Private equity	-	-	1	1
Insurance contracts	-	-	48,879	48,879
Total assets	\$ 252,635	\$ 2,207,885	\$ 683,154	\$ 3,143,674
Pending transactions				(132,758)
Total net assets				\$ 3,010,916
March 31, 2025				
	Level 1	Level 2	Not categorized	Total
	<i>(in thousands of dollars)</i>			
Pension assets:				
Equity	\$ 55	\$ -	\$ 82,069	\$ 82,124
Diversified alternatives	-	-	26,404	26,404
Corporate bonds	-	621,384	151,356	772,740
Government securities	6,963	353,902	191,993	552,858
Private equity	-	-	226,816	226,816
Real estate	-	-	77,612	77,612
Infrastructure	-	-	118,098	118,098
Total assets	\$ 7,018	\$ 975,286	\$ 874,348	\$ 1,856,652
Pending transactions				(62,199)
Total net assets				\$ 1,794,453
PBOP assets:				
Equity	\$ 40,464	\$ -	\$ 454,531	\$ 494,995
Diversified alternatives	133,413	-	-	133,413
Corporate bonds	-	1,747,400	-	1,747,400
Government securities	44,302	379,442	573	424,317
Private equity	-	-	15	15
Insurance contracts	-	-	42,043	42,043
Total assets	\$ 218,179	\$ 2,126,842	\$ 497,162	\$ 2,842,183
Pending transactions				28,878
Total net assets				\$ 2,871,061

The methods used to fair value pension and PBOP assets are described below:

Equity: Equity includes both actively and passively managed assets, with investments in domestic equity index funds as well as international equities.

Diversified alternatives: Diversified alternatives consist of holdings of global tactical assets allocation funds that seek to invest opportunistically in a range of asset classes and sectors globally.

Corporate bonds: Corporate bonds consist of debt issued by various corporations and corporate money market funds. Corporate bonds also include small investments in preferred securities, as these are used in the fixed income portfolios as yield-producing investments. In addition, certain fixed income derivatives are included in this category such as credit default swaps, to assist in managing credit risk.

Government securities: Government securities include individual U.S. agency, treasury securities, state and local municipal bonds, as well as a U.S. Treasury exchange-traded fund. The Plans also include a small amount of non-U.S. government debt which is also captured here. U.S. government money market funds are also included. In addition, interest rate futures and swaps are held as a tool to manage interest rate risk.

Private equity: Private equity consists of limited partnerships investments where all the underlying investments are privately held. This primarily consists of buy-out investments, with smaller allocations to venture capital.

Real estate: Real estate consists of limited partnership investments, primarily in U.S. core open-end real estate funds as well as some core-plus closed-end real estate funds.

Infrastructure: Infrastructure consists of limited partnerships investments that seek to invest in physical assets that are considered essential for a society to facilitate the orderly operation of its economy. Investments in infrastructure typically include transportation assets (such as airports and toll roads) and utility-type assets. Investments in infrastructure funds are utilized as a diversifier to other asset classes within the pension portfolio. Infrastructure investments are also typically income-producing assets.

Insurance contracts: Insurance contracts consist of Trust-Owned Life Insurance.

Not categorized: For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and they are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Pending transactions: Accounts receivable and accounts payable are short-term cash transactions that are expected to settle within a few days of the measurement date.

Defined Contribution Plans

NGUSA has defined contribution retirement plans that cover substantially all employees. For the years ended March 31, 2026, 2025, and 2024, the Company recognized an expense in the accompanying statements of operations of \$5.2 million, \$5.0 million, and \$4.9 million, respectively, for matching contributions.

11. CAPITALIZATION

Total capitalization for the Company at March 31, 2026 and 2025 is as follows:

			March 31,	
			2026	2025
<i>(in thousands of dollars)</i>				
Total shareholders' equity			\$ 3,879,034	\$ 3,719,006
Long-term debt:	<u>Interest Rate</u>	<u>Maturity Date</u>		
Senior note	1.73%	November 24, 2030	500,000	500,000
Senior note	5.90%	November 15, 2039	800,000	800,000
Senior note	4.00%	August 15, 2046	500,000	500,000
Senior note	5.87%	February 26, 2054	400,000	400,000
Total debt			2,200,000	2,200,000
Unamortized debt discount			(1,779)	(1,862)
Unamortized debt issuance costs			(9,431)	(10,146)
Total long-term debt			2,188,790	2,187,992
Total capitalization			\$ 6,067,824	\$ 5,906,998

As of March 31, 2026, the Company has \$500 million long-term debt maturing within the next five years, and the total amount maturing thereafter is \$1.7 billion.

The Company's debt agreements and banking facilities contain general covenants, including those relating to the periodic and timely provision of financial information by the issuing entity, and financial covenants, such as restrictions on the level of indebtedness. Failure to comply with these covenants, or to obtain waivers of those requirements, could in some cases trigger a right, at the lender's discretion, to require repayment of some of the Company's debt, and may restrict the Company's ability to draw upon its facilities or access the capital markets. As of March 31, 2026 and 2025, the Company was in compliance with all such covenants.

Debt Authorizations

The Company has regulatory approval from the FERC to issue up to \$750.0 million of short-term debt internally or externally that expires on October 14, 2026. The Company had no external short-term debt as of March 31, 2026 and 2025. Refer to the Intercompany Money Pool section in Note 16, "Related Party Transactions", for short-term debt outstanding with affiliated companies.

On July 17, 2023, the Company received approval from the DPU to issue up to \$1.1 billion of long-term debt in one or more transactions through August 31, 2024. Under this authorization, the Company has issued \$900.0 million of long-term debt as of March 31, 2026 and 2025, respectively.

On February 5, 2026, the Company received approval from the DPU to issue up to \$1.4 billion of long-term debt in one or more transactions through February 5, 2029. Under this most recent authorization, the Company has issued no long-term debt as of March 31, 2026.

Dividend Restrictions

Pursuant to the Company's preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on the payment of common stock dividends would come into effect if the common stock equity was, or by reason of the payment of such dividends became, less than 25% of total capitalization. The Company was in compliance with this covenant,

and, accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions as of March 31, 2026 or 2025.

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding, which can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock.

A summary of cumulative preferred stock is as follows:

Series	Shares Outstanding		Amount		Call Price
	March 31,		March 31,		
	2026	2025	2026	2025	
	<i>(in thousands of dollars, except per share and number of shares data)</i>				
\$100 par value - 4.44% Series	22,585	22,585	\$ 2,259	\$ 2,259	\$ 104.068

The Company did not redeem any preferred stock as of March 31, 2026, 2025, or 2024. The annual dividend requirement for cumulative preferred stock was \$0.1 million as of March 31, 2026, 2025, and 2024.

12. INCOME TAXES

Components of Income Tax Expense (Benefit)

	Years Ended March 31,		
	2026	2025	2024
	<i>(in thousands of dollars)</i>		
Current tax expense (benefit):			
Federal	\$ 60,398	\$ 31,599	\$ (24,094)
State	17,153	2,203	(5,239)
Total current tax expense (benefit)	<u>77,551</u>	<u>33,802</u>	<u>(29,333)</u>
Deferred tax expense (benefit):			
Federal	(35,128)	2,834	56,283
State	(1,721)	16,550	22,724
Total deferred tax expense (benefit)	<u>(36,849)</u>	<u>19,384</u>	<u>79,007</u>
Amortized investment tax credits ⁽¹⁾	<u>(2,596)</u>	<u>(2,596)</u>	<u>(2,596)</u>
Total deferred tax expense (benefit)	<u>(39,445)</u>	<u>16,788</u>	<u>76,411</u>
Total income tax expense	<u>\$ 38,106</u>	<u>\$ 50,590</u>	<u>\$ 47,078</u>

⁽¹⁾ Investment tax credits ("ITC") are accounted for using the deferral and gross-up method of accounting and are amortized over the depreciable life of the property giving rise to the credits.

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2026, 2025, and 2024 are 20.7%, 22.4%, and 24.1%, respectively. The following table presents a reconciliation of income tax expense (benefit) at the federal statutory tax rate of 21.0% to the actual tax expense:

	Years Ended March 31,					
	2026		2025		2024	
	Amount	Rate	Amount	Rate	Amount	Rate
	<i>(in thousands of dollars)</i>					
U.S. federal income tax	\$ 38,639	21.0%	\$ 47,450	21.0%	\$ 40,960	21.0%
State & local income tax, net of federal benefit ⁽¹⁾	12,260	6.7%	14,813	6.6%	13,293	6.8%
Tax credits	(2,596)	-1.4%	(2,696)	-1.2%	(2,596)	-1.3%
Changes in unrecognized tax benefits	-	-	17	0.0%	1,029	0.5%
Other adjustments						
Amortization of excess deferred income taxes	(9,343)	-5.1%	(8,103)	-3.6%	(6,205)	-3.2%
Allowance for equity funds used during construction	-	-	(132)	-0.1%	55	0.0%
Other	(854)	-0.5%	(759)	-0.3%	542	0.3%
Effective income tax rate	\$ 38,106	20.7%	\$ 50,590	22.4%	\$ 47,078	24.1%

⁽¹⁾ State taxes in Massachusetts made up the majority of the tax effect of this category.

For each period presented, the Company's income from continuing operations before income tax expense was entirely attributable to domestic (U.S.) operations.

The Company is included in the NGNA and subsidiaries' consolidated federal income tax return, and Massachusetts unitary state income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

Tax Legislative Enactments

The Inflation Reduction Act ("IRA"), enacted in August 2022, imposes a 15.0% CAMT on the "adjusted financial statement income" of certain large corporations that qualify as an "applicable corporation" for tax years beginning after December 31, 2022. Once a corporation qualifies as an applicable corporation, it remains one for all future taxable years. National Grid meets the qualifications of an applicable corporation and is therefore subject to CAMT beginning with the fiscal year ended March 31, 2024. Any CAMT amount paid will generate a CAMT credit carryforward that has no expiration period and can be claimed against regular income tax in the future.

On February 18, 2026, the US Treasury Department issued Notice 2026-07 (the "Notice"), which provides interim guidance on the application of CAMT. The Notice permits corporate taxpayers to deduct certain depreciable property in computing CAMT liability. National Grid analyzed the guidance and concluded that it is applicable to the Company in the fiscal year ended March 31, 2026, and applies retroactively to fiscal years 2024 and 2025. The Company intends to file amended returns for the US federal tax jurisdiction for the CAMT liability, for years March 31, 2024 and March 31, 2025, due to the release of the Notice.

On July 4, 2025, the One Big Beautiful Bill Act ("OBBBA") was signed into law. OBBBA contains a number of tax provisions that extend and modify certain tax provisions enacted as part of the Tax Cuts and Jobs Act of 2017 and Inflation Reduction Act of 2022. The tax provisions of the OBBBA do not have a material impact on the results of operations, cash flows, or financial position of the Company.

Deferred Tax Components

	March 31,	
	2026	2025
	<i>(in thousands of dollars)</i>	
Deferred tax assets:		
Allowance for doubtful accounts	\$ 54,401	\$ 55,676
Environmental remediation costs	22,220	20,650
Regulatory liabilities	261,063	160,597
Renewable energy certificate obligations	31,323	36,974
Reserves not currently deducted	26,970	21,587
Investment tax credit carryforward	20,435	-
Corporate alternative minimum tax credit	2,894	16,530
Other items	19,596	23,546
Total deferred tax assets	<u>438,902</u>	<u>335,560</u>
Deferred tax liabilities:		
Property related differences	662,392	620,380
Regulatory assets	392,711	376,081
Other items	45,835	23,799
Total deferred tax liabilities	<u>1,100,938</u>	<u>1,020,260</u>
Net deferred income tax liabilities	662,036	684,700
Deferred investment tax credits	25,205	27,800
Deferred income tax liabilities, net	<u>\$ 687,241</u>	<u>\$ 712,500</u>

Net Operating Losses

The amounts and expiration dates of the Company's net operating losses carryforward as of March 31, 2026 are as follows:

	<u>Carryforward Amount</u>	<u>Expiration Period</u>
	<i>(in thousands of dollars)</i>	
Federal	\$ 72,658	Indefinite
Massachusetts	33,142	2044

As a result of the accounting for uncertain tax positions, the amount of deferred tax assets reflected in the financial statements is less than the amount of the tax effect of the federal and state net operating losses carryforward reflected on the income tax returns.

Status of Income Tax Examinations

The following table indicates the earliest tax year subject to examination for each major jurisdiction:

<u>Jurisdiction</u>	<u>Tax Year</u>
Federal	March 31, 2023
Massachusetts	March 31, 2013

Uncertain Tax Positions

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other income, net, in the accompanying statements of operations. As of March 31, 2026 and 2025, the Company has accrued for interest related to unrecognized tax benefits of \$1.4 million and \$0.3 million, respectively. During the years ended March 31, 2026, 2025, and 2024, the Company recorded interest expense of \$1.1 million, interest expense of \$0.2 million, and interest income of \$0.1 million, respectively. No tax penalties were recognized during the years ended March 31, 2026, 2025, and 2024.

Income Taxes Refunded (Paid), net

	Year Ended March 31, 2026	
	<i>(in thousands of dollars)</i>	
Federal	\$	(15,127)
Massachusetts		(4,945)
Total income tax refunded (paid), net	\$	(20,072)

13. ENVIRONMENTAL MATTERS

The normal ongoing operations and historic activities of the Company are subject to various federal, state, and local environmental laws and regulations. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

The United States Environmental Protection Agency ("EPA") and the Massachusetts Department of Environmental Protection ("DEP"), as well as private entities, have alleged that the Company is a potentially responsible party under state or federal law for the remediation of numerous sites. The Company's most significant liabilities relate to former Manufactured Gas Plant ("MGP") facilities, which were formerly owned or operated by the Company. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA and DEP.

The Company estimated the remaining costs of environmental remediation activities were \$80.8 million and \$75.0 million as of March 31, 2026 and 2025, respectively. These liabilities are expected to be settled over approximately 33 years, and these undiscounted amounts have been recorded as estimated liabilities on the balance sheet. Substantially all environmental remediation costs are expected to be recoverable through rates, resulting in corresponding regulatory assets and liabilities. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, the Company may seek additional recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The DPU has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Massachusetts. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability on the balance sheet. Rate-recoverable contributions of approximately \$5.3 million and \$5.2 million were made to the fund during the years ended March 31, 2026 and 2025, respectively, along with interest, lease payments, and any recoveries from insurance carriers and other third parties. Accordingly, as of March 31, 2026 and 2025, the Company has recorded environmental regulatory assets of \$78.7 million and \$73.0 million, respectively, and environmental regulatory liabilities of \$22.4 million and \$19.5 million, respectively. See Note 5, "Regulatory Assets and Liabilities", for additional details.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in compliance with all applicable environmental laws. Where the Company has regulatory recovery, it believes that the

obligations imposed on it because of environmental laws will not have a material impact on its results of operations or financial position.

14. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company has several contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payments. In addition, the Company has various capital commitments related to the construction of property, plant, and equipment.

The Company’s commitments under these contracts for the years subsequent to March 31, 2026 are summarized in the table below:

<i>(in thousands of dollars)</i>	Energy	Capital
Years Ending March 31,	Purchases	Expenditures
2027	\$ 691,582	\$ 85,245
2028	468,733	10,895
2029	479,085	1,134
2030	489,744	2,012
2031	493,749	-
Thereafter	8,390,316	-
Total	<u>\$ 11,013,209</u>	<u>\$ 99,286</u>

Power Purchase Agreements for Renewable Energy Projects

Section 83A

On February 26, 2014, the DPU approved three long-term (20-year) contracts for the purchase of electricity and renewable energy credits from three separate wind-powered generating facilities. The approval by the DPU allows the Company, along with Nantucket Electric (collectively “the Massachusetts Electric Companies”), to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made under the contracts.

Three-State Procurement: Section 83A

On June 15, 2018, the DPU approved ten long-term (20-year) contracts for the purchase of electricity and renewable energy credits from ten separate generating facilities. The Massachusetts Electric Companies would purchase the actual output generated by the individual facilities, which in aggregate represents approximately 91 MWs of nameplate capacity. The approval by the DPU allows the Massachusetts Electric Companies to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made under the contracts.

Clean Energy Procurement: Section 83D

On June 13, 2018, the Massachusetts Electric Companies entered into two separate agreements for the transportation and purchase of electricity and the related environmental attributes from hydroelectric facilities located in the Canadian province of Québec. The two agreements were entered into pursuant to Section 83D of the Green Communities Act. The DPU approved the Section 83D contracts on June 25, 2019, and the Massachusetts Electric Companies will be able to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made.

The first agreement is a 20-year PPA with H.Q. Energy for the purchase of approximately 498 megawatt-hours of electricity and the related environmental attributes from a portfolio of hydroelectric facilities owned and operated by affiliates of H.Q. Energy. The second agreement is a 20-year transmission service agreement (“TSA”) with NECEC Transmission LLC (“NECEC”).

The TSA provides for the transmission of the electricity supplied by H.Q. Energy on a new transmission line that runs from the United States border to Lewiston, Maine, where it interconnects with the ISO-NE system.

The project became operational on January 16, 2026, enabling the delivery of hydroelectric power from Québec to the ISO-NE grid under the terms of the contracts, along with recovery of 2.75% remuneration on the annual payments made. This milestone marks the commencement of contracted energy flows pursuant to the Section 83D agreements.

Offshore Wind Energy Procurement: Section 83C Round 1

On July 31, 2018, the Massachusetts Electric Companies entered into two separate 20-year PPAs with Vineyard Wind LLC (“Vineyard Wind”) for the purchase of 46.16% of the electricity and renewable energy credits generated by two offshore wind farms proposed by Vineyard Wind, with each individual wind farm having a capacity of up to 400 MWs. The contracts with Vineyard Wind were entered into pursuant to Section 83C of the Green Communities Act. On April 12, 2019, the DPU approved the contracts, and the Massachusetts Electric Companies will be able to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made. On March 25, 2024, Vineyard Wind notified the Massachusetts Electric Distribution Companies (“MA EDCs”) of their intent to utilize critical milestone extensions in the Facility 1 and Facility 2 PPAs. As such, the new guaranteed commercial operations dates are January 15, 2026 for the Facility 1 PPA and May 31, 2026 for the Facility 2 PPA.

On December 22, 2025, the Bureau of Ocean Energy Management (“BOEM”) ordered Vineyard Wind 1 to suspend all on-lease project activities for 90 days due to national security concerns. The order permitted Vineyard Wind 1 to maintain its current deliveries to ISO-NE during the suspension. On January 15, 2026, Vineyard Wind filed for a temporary restraining order seeking permission to continue construction while awaiting a ruling on a related motion for a temporary injunction, also submitted on January 15, 2026. On January 27, 2026, the U.S. District Court for the District of Massachusetts granted the project a preliminary injunction, allowing the project to resume full construction activities.

The project became operational with a capacity deficiency on April 24, 2026, enabling the delivery of offshore wind power under the terms of the contracts, along with recovery of 2.75% remuneration on the annual payments made. This milestone marks the commencement of contracted energy flows pursuant to the Section 83C Round 1 agreement.

Offshore Wind Energy Procurement and Termination: Section 83C Round 2 and Round 3

In 2020 and 2022, the MA EDCs entered into several 20-year PPAs with two developers for the purchase of a portion of the electricity and renewable energy credits generated by two offshore wind farms proposed. The contracts were entered into pursuant to Section 83C of the Green Communities Act and were approved by the DPU. In 2022, both developers indicated that they were unable to build their projects under their awarded contract prices. After negotiations with the MA EDCs, both counterparties elected to request amendments to their contracts allowing for Termination and Release. In July and August 2023, the MA EDCs filed amendment to these PPAs allowing for termination and requiring a payment to be returned to each EDC’s customers. The DPU approved these amendments and the contracts were terminated in late 2023. The Company received termination payments totaling approximately \$49.0 million, which were returned to customers via bills between March 1, 2024, and February 28, 2025.

Legal Matters

The Company is subject to various legal proceedings arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, to its business or likely to result in a material adverse effect on its results of operations, financial position, or cash flows.

Financial Guarantees

The Company unconditionally guarantees the full and prompt payment of the principal, premium, if any, and interest on certain tax-exempt bonds issued by the Massachusetts Development Finance Agency in connection with Nantucket Electric's financing of its first and second underground and submarine cable projects. The Company would be required to make any principal, interest, and premium payments if Nantucket Electric failed to pay. The carrying value of the debt guaranteed is approximately \$51.3 million as of March 31, 2026, and the debt has maturities extending through 2042. This guarantee is absolute and unconditional. As of the date of this report, the Company has not had a claim made against it for this guarantee and has no reason to believe that Nantucket Electric will default on its obligations.

15. LEASES

The Company has various operating leases, primarily related to buildings, land, and fleet vehicles used to support its electric operations, with lease terms ranging between 1 and 31 years.

Operating lease ROU assets are included in property, plant, and equipment, net, and operating lease liabilities are included in other current liabilities and other noncurrent liabilities on the balance sheet. As of March 31, 2026 and 2025, the Company did not have any finance leases.

The expense related to operating leases was \$21.0 million, \$16.1 million, and \$15.6 million for the years ended March 31, 2026, 2025, and 2024, respectively.

As of March 31, 2026 and 2025, the Company did not have material rights or obligations under operating leases that have not yet commenced.

The following table presents the components of cash flows arising from lease transactions and other operating lease-related information:

	Years Ended March 31,		
	2026	2025	2024
	<i>(in thousands of dollars)</i>		
Cash paid for amounts included in lease liabilities			
Operating cash flows from operating leases	\$ 21,043	\$ 16,097	\$ 15,650
ROU assets obtained in exchange for new operating lease liabilities	36,382	21,181	21,559
Weighted average remaining lease term – operating leases	7 years	7 years	8 years
Weighted average discount rate – operating leases	4.7%	4.3%	3.9%

For any leases that do not provide an implicit rate, the Company uses an estimate of its collateralized incremental borrowing rate, based on the information available at the commencement date to determine the present value of future payments.

The following table contains the Company's maturity analysis of its operating lease liabilities as of March 31, 2026, showing the undiscounted cash flows on an annual basis reconciled to the discounted operating lease liabilities recognized in the comparative balance sheet:

<u>Year Ending March 31,</u>	<u>Operating Leases</u> <i>(in thousands of dollars)</i>
2027	\$ 20,599
2028	19,112
2029	16,485
2030	14,003
2031	11,146
Thereafter	22,684
Total future minimum lease payments	104,029
Less: imputed interest	14,531
Total	<u>\$ 89,498</u>
Reported as of March 31, 2026:	
Current lease liability	\$ 16,877
Non-current lease liability	72,621
Total	<u>\$ 89,498</u>

There are operating leases in which the Company is the lessor. Revenue under such leases was \$17.2 million and \$21.2 million for the years ended March 31, 2026 and 2025, respectively and immaterial for the year ended March 31, 2024.

16. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, and treasury/finance), human resources, information technology, legal, and strategic planning, that are charged between the companies and charged to each company.

The Company records short-term receivables for any deposits held by affiliates that are due to the Company, and payables for any deposits held by the Company that are due to affiliates, in the ordinary course of business. The amounts receivable from, and payable to, its affiliates do not bear interest and are settled through the intercompany money pool.

A summary of outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	<u>Accounts Receivable</u> <u>from Affiliates</u>		<u>Accounts Payable</u> <u>to Affiliates</u>	
	<u>March 31,</u>		<u>March 31,</u>	
	<u>2026</u>	<u>2025</u>	<u>2026</u>	<u>2025</u>
	<i>(in thousands of dollars)</i>			
Boston Gas Company	\$ 1,304	\$ 18	\$ 861	\$ 2,157
Nantucket Electric Company	878	475	1,732	1,580
New England Power Company	256,955	4,600	111,078	99,758
NGUSA	219	2,119	3,630	3,233
NGUSA Service Company	11,778	18,134	138,291	119,900
Other Affiliates	342	97	535	766
Total	<u>\$ 271,476</u>	<u>\$ 25,443</u>	<u>\$ 256,127</u>	<u>\$ 227,394</u>

As discussed in Note 6, "Rate Matters", NEP operates the pooled transmission facilities of the Company and NEP as a single integrated system ("NEPOOL") under NEP's Tariff No. 1. These transmission services are regulated by both the ISO-NE and

the FERC. NEP charges the ISO-NE for these transmission services. As NEP is the sole operator of the NEPOOL assets, ISO-NE revenues are remitted from NEP to the Company, representing the substantial portion of the accounts receivable due from NEP.

In turn, the ISO-NE charges the Company for RNS, with some of those charges being associated with the Company-owned transmission assets in the NEPOOL. \$70.3 million and \$69.2 million of the unpaid charges from the ISO-NE to the Company have been presented as a payable to NEP related to these Company-owned transmission assets as of March 31, 2026 and 2025, respectively. Additionally, NEP charges the Company for LNS. The amounts paid to NEP for RNS and LNS for the years ended March 31, 2026, 2025, and 2024 were \$660.4 million, \$591.5 million, and \$476.8 million, respectively. These amounts are presented within operations and maintenance expense in the accompanying statements of operations.

Advances from Affiliate

On January 15, 2026, the Company received Board authorization for noninterest-bearing open account advances up to \$750 million through March 31, 2028, to be received from NGUSA for working capital needs. As of March 31, 2026, the Company had no outstanding advances from affiliate.

Intercompany Money Pool

The settlement of the Company's various transactions with NGUSA and certain affiliates generally occurs via the intercompany money pool in which it participates. The Company is a participant in the regulated money pool and can both borrow and invest funds. Borrowings from the regulated money pool bear interest in accordance with the terms of the regulated money pool Agreement. As the Company fully participates in the regulated money pool rather than settling intercompany charges with cash, all changes in the intercompany money pool balance are reflected as investing or financing activities in the accompanying statements of cash flows. For the purpose of presentation in the statements of cash flows, it is assumed all amounts settled through the intercompany money pool are constructive cash receipts and payments, and therefore are presented as such.

The regulated money pool is funded by operating funds from participants. NGUSA has the ability to borrow up to \$3.0 billion from National Grid plc for working capital needs, including funding of the regulated money pool, if necessary. The Company had short-term intercompany money pool borrowings of \$321.8 million and money pool investments of \$19.9 million as of March 31, 2026 and 2025, respectively. The average interest rates for the intercompany money pool were 4.5%, 5.1%, and 5.2% for the years ended March 31, 2026, 2025, and 2024, respectively.

Additionally, NGUSA had committed revolving credit facilities of approximately \$6.8 billion, all of which have expiry dates beyond May 2027, with an annual extension option. Since March 31, 2026, the facilities have been extended and now expire beyond May 2028. As of March 31, 2026, these facilities have not been drawn against and can be used to fund the money pool.

Related Party Reimbursement

In accordance with the Credit and Operating Support Agreement dated March 26, 1996, the Company will reimburse Nantucket Electric an amount equal to the difference between Nantucket Electric's actual net income for the year and the net income necessary for Nantucket Electric to earn its DPU-approved ROE for the year, which is currently 9.35%. This reimbursement represents additional revenue to Nantucket Electric and expense to the Company. If Nantucket Electric's actual ROE for the year exceeds its allowed ROE, there is no reimbursement. For the years ended March 31, 2026, 2025, and 2024, the Company reimbursed Nantucket Electric \$8.2 million, \$6.9 million, and \$8.7 million, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at cost, without a mark-up. The service company costs are generally allocated to affiliated companies through a tiered approach. First and foremost, costs are directly

charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, and total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator determined using a 3-point formula based on net margin, net property, plant, and equipment, and operations and maintenance expense.

Charges from the service companies of NGUSA to the Company are mostly related to traditional administrative support functions. For the years ended March 31, 2026, 2025, and 2024, costs allocated to the Company were \$689.4 million, \$593.6 million, and \$527.3 million, respectively.