National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2026 and 2025

NATIONAL GRID USA AND SUBSIDIARIES

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
National Grid USA

Opinion

We have audited the consolidated financial statements of National Grid USA and Subsidiaries (the "Company"), which comprise the consolidated balance sheets as of March 31, 2026 and 2025, and the related consolidated statements of operations and comprehensive income, cash flows and changes in equity for the years then ended, and the related notes to the consolidated 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 the years then ended 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 29, 2026

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(in millions of dollars)

	Years Ended March 31,	
	2026	2025
Operating revenues	**$ 16,647**	$ 14,441
Operating expenses:		
Purchased electricity	**2,205**	1,903
Purchased gas	**2,647**	1,863
Operations and maintenance	**5,953**	5,298
Depreciation and amortization	**2,076**	1,801
Other taxes	**1,624**	1,515
Total operating expenses	**14,505**	12,380
Operating income	**2,142**	2,061
Other income (deductions):		
Interest on long-term debt, net	**(912)**	(814)
Other interest, including affiliate interest, net	**(128)**	(167)
Other income, net	**827**	634
Total other income (deductions)	**(213)**	(347)
Income before income taxes	**1,929**	1,714
Income tax expense	**432**	324
Net income	**1,497**	1,390
Net income attributed to non-controlling interest	**(2)**	(2)
Dividends on preferred stock	**(593)**	(593)
Net income attributed to common shareholders	**$ 902**	$ 795
Other comprehensive income, net of taxes:		
Unrealized gains (losses) on securities, net of tax expense (benefit) of $1 and $0 in 2026 and 2025, respectively	**2**	(1)
Change in pension and other postretirement obligations, net of tax expense of $13 and $4 in 2026 and 2025, respectively	**34**	8
Total other comprehensive income	**36**	7
Comprehensive income	**$ 1,533**	$ 1,397
Less: Comprehensive income attributed to non-controlling interest	**(2)**	(2)
Comprehensive income attributed to common shareholders	**$ 1,531**	$ 1,395

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Years Ended March 31,	
	2026	2025
Operating activities:		
Net income	**$ 1,497**	$ 1,390
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**2,076**	1,801
Regulatory amortizations	**89**	37
Deferred income tax expense and amortization of investment tax credits	**473**	276
Bad debt expense	**347**	308
Gain on sale of assets	**(19)**	-
Allowance for equity funds used during construction	**(121)**	(99)
Pension and postretirement (benefit) expense, net	**(164)**	9
Other, net	**3**	47
Pension, postretirement benefits and other contributions, net	**(35)**	(215)
Environmental remediation payments	**(145)**	(157)
Changes in operating assets and liabilities:		
Accounts receivable, other receivables, and unbilled revenues, net	**(566)**	(921)
Accounts receivable from/payable to affiliates, net	**455**	(44)
Inventory	**(28)**	88
Regulatory assets and liabilities (current), net	**(487)**	(53)
Regulatory assets and liabilities (non-current), net	**432**	(65)
Derivative instruments, net	**(46)**	(179)
Environmental remediation costs	**125**	18
Accounts payable and other liabilities	**110**	180
Transmission congestion contracts	**1**	(34)
Other assets and liabilities, net	**209**	133
Net cash provided by operating activities	**4,206**	2,520
Investing activities:		
Capital expenditures	**(6,627)**	(5,901)
Cost of removal	**(261)**	(222)
Proceeds from sale of assets	**38**	19
Intercompany money pool	**1,424**	(850)
Repayment of advance to affiliate	**-**	78
Purchases of financial investments	**(67)**	(90)
Proceeds from sales of financial investments	**80**	104
Other, net	**10**	16
Net cash used in investing activities	**(5,403)**	(6,846)

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

Financing activities:		
Preferred stock dividends	**(593)**	(593)
Payments on long-term debt	**(648)**	(523)
Issuance of long-term debt	**3,308**	1,105
Payment of debt issuance costs	**(20)**	(6)
Intercompany money pool	**(167)**	95
Changes in advances from affiliates, net	**(666)**	3,215
Other	**7**	-
Net cash provided by financing activities	**1,221**	3,293
Net increase (decrease) in cash, cash equivalents, restricted cash and special deposits	**24**	(1,033)
Cash, cash equivalents, restricted cash and special deposits, beginning of year	**595**	1,628
Cash, cash equivalents, restricted cash and special deposits, end of year	**$ 619**	$ 595
Supplemental disclosures:		
Interest paid, net of amounts capitalized	**$ (879)**	$ (887)
Income taxes refunded (paid), net	**(12)**	(30)
Significant non-cash items:		
Capital-related accruals included in accounts payable	**369**	315
Parent tax loss allocation	**53**	49
Asset retirement obligation - revision to present value	**(11)**	-
ROU assets obtained in exchange for operating lease liabilities	**232**	201

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31,	
	2026	2025
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 485**	$ 471
Restricted cash and special deposits	**134**	124
Accounts receivable, net	**3,056**	2,835
Accounts receivable from affiliates	**141**	698
Intercompany money pool	**1,704**	3,128
Unbilled revenues, net	**775**	705
Inventory	**626**	598
Regulatory assets	**985**	704
Prepaid taxes	**195**	185
Other, net	**294**	363
Total current assets	**8,395**	9,811
Property, plant and equipment, net	**56,566**	51,280
Non-current assets:		
Regulatory assets	**6,140**	6,288
Goodwill	**6,291**	6,295
Postretirement benefits	**2,228**	1,780
Financial investments	**537**	524
Other, net	**625**	457
Total non-current assets	**15,821**	15,344
Total assets	**$ 80,782**	$ 76,435

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31,	
	2026	2025
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other	**$ 2,398**	$ 2,093
Accounts payable to affiliates	**311**	413
Intercompany money pool	**701**	868
Advances from affiliates	**11,578**	12,244
Current portion of long-term debt	**788**	648
Taxes accrued	**257**	156
Interest accrued	**226**	186
Regulatory liabilities	**718**	924
Derivative instruments	**33**	14
Renewable energy certificate obligations	**169**	193
Payroll and benefits accruals	**532**	500
Environmental remediation obligations	**222**	216
Other	**917**	798
Total current liabilities	**18,850**	19,253
Non-current liabilities:		
Regulatory liabilities	**7,819**	6,837
Asset retirement obligations	**158**	167
Deferred income tax liabilities, net	**6,630**	6,035
Postretirement benefits	**322**	524
Environmental remediation obligations	**2,876**	2,902
Operating lease liabilities	**843**	789
Other	**746**	922
Total non-current liabilities	**19,394**	18,176
Commitments and contingencies (Note 14)		
Long-term debt	**20,426**	17,918
Equity:		
Common stock and additional paid-in capital	**14,148**	14,071
Retained earnings	**7,767**	6,865
Accumulated other comprehensive income	**118**	82
Common shareholders' equity	**22,033**	21,018
Non-controlling interest	**79**	70
Total equity	**22,112**	21,088
Total liabilities and equity	**$80,782**	$ 76,435

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Common Stock [1]	Cumulative Preferred Stock [2]	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Unrealized Gain (Loss) on Securities	Accumulated Other Comprehensive Income (Loss): Pension and Other Post-retirement Benefits	Accumulated Other Comprehensive Income (Loss): Total Accumulated Other	Retained Earnings	Non-Controlling Interest [3]	Total
Balance as of March 31, 2024	$ -	$ -	$ 14,002	$ (4)	$ 79	$ 75	$ 6,070	$ 64	$ 20,211
Net income	-	-	-	-	-	-	1,388	2	1,390
Other comprehensive income (loss):									
Unrealized gains (losses) on securities, net of $0 tax expense (benefit)	-	-	-	(1)	-	(1)	-	-	(1)
Change in pension and other postretirement obligations, net of $4 tax expense	-	-	-	-	8	8	-	-	8
Total comprehensive income									1,397
Parent loss tax allocation	-	-	49	-	-	-	-	-	49
Stock-based compensation	-	-	20	-	-	-	-	-	20
Preferred stock dividends	-	-	-	-	-	-	(593)	-	(593)
Other equity transactions with non-controlling interest	-	-	-	-	-	-	-	4	4
Balance as of March 31, 2025	$ -	$ -	$ 14,071	$ (5)	$ 87	$ 82	$ 6,865	$ 70	$ 21,088
Net income	-	-	-	-	-	-	1,495	2	1,497
Other comprehensive income (loss):									
Unrealized gains (losses) on securities, net of $1 tax expense (benefit)	-	-	-	2	-	2	-	-	2
Change in pension and other postretirement obligations, net of $13 tax expense	-	-	-	-	34	34	-	-	34
Total comprehensive income									1,533
Parent loss tax allocation	-	-	53	-	-	-	-	-	53
Stock-based compensation	-	-	24	-	-	-	-	-	24
Preferred stock dividends	-	-	-	-	-	-	(593)	-	(593)
Other equity transactions with non-controlling interest	-	-	-	-	-	-	-	7	7
Balance as of March 31, 2026	$ -	$ -	$ 14,148	$ (3)	$ 121	$ 118	$ 7,767	$ 79	$ 22,112

(1) National Grid USA ("NGUSA") had 641 shares of common stock authorized, issued and outstanding, with a par value of $0.10 per share.

(2) NGUSA had 915 shares of cumulative preferred stock authorized, issued and outstanding, with a par value of $0.10 per share. See Note 17, "*Preferred Stock*".

(3) NGUSA subsidiaries had 323,552 shares of cumulative preferred stock authorized, issued and outstanding, with par values of either $100 or $1 per share at March 31, 2026 and 2025, respectively. See Note 17, "*Preferred Stock*".

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

NATIONAL GRID USA AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

National Grid USA ("NGUSA" or "the Company") is 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 (the "Parent"), a public limited company incorporated under the laws of England and Wales.

NGUSA has two major lines of business, "Gas Distribution" and "Electric Services," and operates various energy services and investment companies. The Company's Gas Distribution business consists of four gas distribution subsidiaries which provide gas distribution services to customers in the areas of central, northern, and eastern New York, the New York City boroughs of Brooklyn, Queens, and Staten Island, and the Long Island Counties of Nassau and Suffolk, as well as the state of Massachusetts. The Company's Electric Services business primarily consists of three electric distribution subsidiaries which provide electric services to customers in the areas of eastern, central, northern, and western New York, as well as the state of Massachusetts. The Company also operates electric transmission facilities in Massachusetts, New Hampshire and Vermont, and provides energy services, supplies capacity, and produces energy for the use of customers of the Long Island Power Authority ("LIPA") on Long Island, New York. The services provided to LIPA through a power supply agreement provide LIPA with electric generating capacity, energy conversion, and ancillary services from the Company's Long Island generating units.

The Company's wholly-owned New England subsidiaries include: New England Power Company ("NEP"), Massachusetts Electric Company ("Massachusetts Electric"), Nantucket Electric Company ("Nantucket"), and Boston Gas Company ("Boston Gas"). The Company's wholly-owned New York subsidiaries include: Niagara Mohawk Power Corporation ("Niagara Mohawk"), National Grid Generation, LLC ("Genco"), The Brooklyn Union Gas Company ("Brooklyn Union"), and KeySpan Gas East Corporation ("KeySpan Gas East"). Certain of the Company's subsidiaries are subject to regulation by state and federal regulatory authorities (see Note 2, *"Summary of Significant Accounting Policies"* for additional details).

The Company also has a 53.7% interest in two hydro-transmission electric companies which are consolidated. The investments in the hydro-transmission electric companies are not material to the Company's consolidated financial statements.

The accompanying consolidated 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 as applicable. The consolidated financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Non-controlling interests of the Company's majority-owned subsidiaries are calculated based upon the respective non-controlling interest ownership percentages. All intercompany transactions with consolidated subsidiaries have been eliminated in consolidation.

Under its holding company structure, the Company does not have significant independent operations or sources of income of its own and conducts most of its operations through its subsidiaries. As a result, the Company depends on the earnings and cash flow of, and dividends or distributions from, its subsidiaries to provide the funds necessary to meet its debt and contractual obligations. Furthermore, a substantial portion of the Company's consolidated assets, earnings, and cash flow is derived from the operations of its regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to the Company is subject to regulation by state regulatory authorities.

The Company has evaluated subsequent events and transactions through June 29, 2026, the date of issuance of these consolidated financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the consolidated financial statements as of and for the year ended March 31, 2026, except as otherwise disclosed in these consolidated financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing consolidated 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 consolidated financial statements. Such estimates and assumptions are reflected in the accompanying consolidated financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the New York Public Service Commission ("NYPSC"), and the Massachusetts Department of Public Utilities ("DPU") regulate the rates the Company's regulated subsidiaries charge their customers in the applicable states. In certain cases, the rate actions of the FERC, NYPSC and DPU can result in accounting that differs from non-regulated companies. In these cases, the subsidiaries defer costs (as regulatory assets) or recognize 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 consolidated balance sheets consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Revenues are recognized by regulated subsidiaries for energy 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 accounting period (see Note 3, "Revenue" for additional details).

The Company recognizes lease income from the sale of capacity and energy to LIPA under terms of the amended and restated Power Supply Agreement ("A&R PSA"), with rates approved by the FERC. The A&R PSA is accounted for as an operating lease (see Note 15, "Leases" 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 of 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's subsidiaries collect 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 gas and electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues), while taxes imposed on the Company, such as excise taxes, are recognized on a gross basis.

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 consists of margin calls to the New York Mercantile Exchange ("NYMEX"), collateral paid to the Company's counterparties for outstanding commodity and financial derivative instruments. There is also restricted cash held by an environmental remediation trust. This cash can only be used by the trust to pay for environmental remediation expenses. Special deposits primarily consist of health care deposits, collateral paid to the Independent System Operator – New England ("ISO-NE") in connection with the ISO-NE's market participant financial assurance requirement. The Company had restricted cash of $60 million and $52 million, and special deposits of $74 million and $72 million as of March 31, 2026 and 2025, respectively.

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, other current assets, and other non-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, gas in storage, purchased renewable energy certificates ("RECs"), and emission credits.

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 or 2025.

Gas in storage is stated at weighted average cost and the related cost is recognized when delivered to customers. Existing rate orders allow the Company to pass directly through to customers the cost of purchased gas, along with any applicable authorized delivery surcharge adjustments. Gas costs passed through to customers are subject to regulatory approvals and are reported periodically to the applicable state regulators.

Renewable Energy Certificates ("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.

Emission credits are comprised of carbon dioxide ("CO2") emission credits, and nitrogen oxide ("NOx") emission credits. Genco's CO2 and NOx emission credits are valued at the lower of weighted average cost or net realizable value and are held primarily for consumption or may be sold to third-party purchasers.

The following table summarizes inventory recorded on the consolidated balance sheets:

	March 31,	
	2026	2025
	(in millions of dollars)	
Materials and supplies	**$ 358**	$ 340
Gas in storage	**120**	121
Purchased RECs	**65**	80
Emission credits	**83**	57
Total inventory	**$ 626**	$ 598

Renewable Energy and Zero-Emissions Credits Obligation

RECs and Zero-Emissions Credits ("ZECs") are stated at cost and are used to measure compliance with State renewable energy standards. RECs support new renewable generation resources whereas ZECs support generation by in-state nuclear power plants and are purchased through the New York State Energy Research and Development Authority ("NYSERDA"). RECs and ZECs are held primarily to be utilized in fulfillment of state compliance obligations.

Transmission Congestion Contracts

The Company participates in the New York Independent System Operator's ("NYISO") Transmission Congestion Contracts ("TCC") Auctions. These auctions are held before the start of the next capability period for both summer and winter. The Company receives proceeds upfront through the NYISO for the sale of these transmission rights on its transmission system. The compensation received is recorded as a current or non-current obligation in which the performance obligation is typically satisfied over a six-month or twelve-month period. See Note 3, "*Revenue*" for additional details.

Derivative Instruments

The Company uses derivative instruments to manage commodity price risk (see Note 8, "*Derivative Instruments*"). All derivative instruments, except commodity contracts that qualify for the normal purchase normal sale exception, are recorded at fair value on the consolidated balance sheets (see Note 9, "*Fair Value Measurements*").

All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Regulatory assets or regulatory liabilities are recorded to defer the recognition of unrealized losses or gains on derivative instruments, respectively.

The Company has certain non-trading instruments for the physical purchase of electricity that qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company was to determine that a contract no longer qualifies for the normal purchase normal sale exception, the Company would recognize the fair value of the contract and, if applicable, account for the gains and losses using the regulatory accounting described above. This has not occurred during the years ended March 31, 2026 or 2025.

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 instrument on a gross basis, with related cash collateral receivable and payable recorded within restricted cash and special deposits, and in other current liabilities, respectively on the consolidated balance sheets.

Power Purchase Agreements

Certain of the Company's subsidiaries enter into power purchase agreements ("PPAs") to procure electricity to serve their 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 other current liabilities on the balance sheet.

Fair Value Measurements

The Company measures derivative instruments, securities, pension and postretirement benefits other than pension plan ("PBOP") assets, and financial investments for which it has elected the fair value option, at fair value. Fair value is the price that would be received to sell an asset or paid 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 an entity 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 certain funds, that meet certain conditions of ASC 820, "*Fair Value Measurement*", 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 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 state authorities. The average composite rates for the years ended March 31, 2026 and 2025 are as follows:

	Composite Rates	
	Years Ended March 31,	
	2026	2025
Electric	**3.0%**	2.9%
Gas	**2.5%**	2.4%
Common	**13.6%**	14.3%

Depreciation expense for regulated subsidiaries includes a component for the estimated cost of removal, 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 cost of removal is removed from the associated regulatory asset or regulatory liability. See Note 5, "*Regulatory Assets and Liabilities*", for additional details.

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 other income, net within the accompanying consolidated statements of operations and comprehensive income. The debt component of AFUDC is reported as an 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 $121 million and $99 million, and AFUDC related to debt of $97 million and $80 million for the years ended March 31, 2026 and 2025, respectively. The average AFUDC rates for the years ended March 31, 2026 and 2025 were 6.5% and 6.8%, 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. For its regulated subsidiaries, 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 and 2025, 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 a reporting unit is below its carrying amount. During the year ended March 31, 2026, the Company tested goodwill residing at NGUSA based upon two identified reporting units, New York and New England.

As of March 31, 2026, the carrying value of goodwill primarily includes amounts assigned to the New England and New York reporting units and amounted to approximately $2,309 million and $3,982 million, respectively. There are no historical accumulated impairment losses included in the carrying values of goodwill.

The goodwill impairment test requires a recoverability test based on the comparison of the Company's estimated fair value for each reporting unit with the reporting unit's 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 allocated carrying amount of goodwill.

For goodwill at the New York and New England reporting units, the Company applies two valuation methodologies to estimate the fair value of its reporting units, 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 balanced 50/50 weighting for each valuation methodology, as it believes that each approach provides equally valuable and reliable information regarding the New York and New England reporting units' estimated fair value.

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

Financial Investments

The Company holds a range of financial investments, including life insurance policies and available-for-sale debt securities.

Corporate owned life insurance policies ("COLI") and Trust owned life insurance policies ("TOLI") are measured at cash surrender value with increases and decreases in the value of these assets recorded in earnings.

Available-for-sale debt securities are measured at fair value with changes in fair value recorded in other comprehensive income. Investments in available-for-sale debt securities are monitored for other than temporary impairment by comparing fair value against amortized cost.

The Company has mutual funds and money market funds representing funds designated for Supplemental Executive Retirement Plans ("SERPs"). These investments are measured at fair value with changes in fair value recorded in earnings.

The following table presents the financial investments recorded on the consolidated balance sheets:

	March 31,	
	2026	2025
	(in millions of dollars)	
COLI/TOLI	**$ 333**	$ 308
Debt securities [1]	**175**	188
SERPs [1]	**29**	28
Total financial investments	**$ 537**	$ 524

[1] See Note 9, "*Fair Value Measurements*" for additional details.

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 gas and electric distribution and electric generation 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 at the credit adjusted risk-free rate.

Accretion and depreciation expenses for the Company's regulated subsidiaries are deferred as part of the Company's asset retirement obligation regulatory asset. As the subsidiaries are rate-regulated, both the depreciation and accretion costs associated with the regulated companies' asset retirement obligation are recorded as increases to regulatory assets on the balance sheets.

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 transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the consolidated financial statements.

Employee Benefits

The Company has defined benefit pension plans and postretirement benefit other than pension plans for its employees. The Company recognizes all pension and PBOP plans' funded status on the consolidated balance sheets as a net liability or asset with an offsetting adjustment to accumulated other comprehensive income ("AOCI") in shareholders' equity. If the cost of providing these plans is recovered in rates through the Company's regulated subsidiaries, the net funded status is partially offset by a regulatory asset or liability. The Company measures and records its pension and PBOP funded status at each year-end. Pension and PBOP plan assets are measured at fair value.

Leases

The Company has various operating leases, primarily related to a transmission line, 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 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 and 2025.

The Company's regulated subsidiaries recognize 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 Financial Accounting Standards Board ("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.

Intangibles – Goodwill and Other-Internal-Use Software (Subtopic 350-40): Internal Use Software

In September 2025, the FASB issued ASU 2025-06, *"Intangibles - Goodwill and Other-Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software"*, which amends the existing standard by removing all references to prescriptive and sequential software development project stages and requiring capitalization of software costs when (1) management has authorized and committed to funding the software project, and (2) it is probable that the project will be completed, and the software will be used to perform the function intended. In evaluating whether it is probable the project will be completed, Management is required to consider whether there is significant uncertainty associated with the development activities of the software.

The Company is required to adopt this standard for annual periods beginning April 1, 2028, with early adoption permitted. Entities may transition using prospective, modified prospective, or retrospective approaches. 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.

Government Grants (Topic 832)

In December 2025, the FASB issued ASU No. 2025-10, *"Government Grants (Topic 832): Accounting for Government Grants Received by Business Entities"*, which added guidance on the recognition, measurement, and presentation of government grants.

The Company is required to adopt this standard for annual period beginning April 1, 2029, and for interim periods within those annual reporting periods, with early adoption permitted. The guidance may be applied on a modified prospective basis, a modified retrospective basis, or a full retrospective basis. 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.

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 and 2025, 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
	(in millions of dollars)	
Revenue from contracts with customers:		
Electric services	**$ 7,229**	$ 6,754
Gas distribution	**8,287**	6,824
Off system sales	**161**	179
Total revenue from contracts with customers	**15,677**	13,757
Revenue from alternative revenue programs	**330**	(65)
Other revenue	**640**	749
Total operating revenues	**$ 16,647**	$ 14,441

Electric Services and Gas Distribution: Revenue from contracts with customers includes electric services and gas distribution. Electric services are comprised of electric distribution and transmission services.

The Company's subsidiaries own and maintain electric and natural gas distribution networks. Distribution revenues are primarily from the sale of electricity, gas, and related services to retail customers. Distribution sales are regulated by the applicable state agencies, which are 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. Gas and electric distribution revenues are derived from the regulated sale and distribution of electricity and natural gas 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 products and services provided along with a return on investment.

The performance obligation related to these sales is to provide electricity or natural gas to the customers on demand. The electricity or natural gas 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 or natural gas as the Company provides these services. The Company records revenues related to distribution sales 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 and natural gas provided to customers by the Company, but not yet billed. Unbilled revenues are determined based on 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 or natural gas from other suppliers. In those circumstances revenue is only recognized for providing delivery of the commodity to the customer.

The Company owns, maintains, and operates an electric transmission system spanning New York, Massachusetts, New Hampshire and Vermont. The Company's transmission services are regulated by the FERC, ISO-NE, and NYISO. Electric transmission revenues arise under TCC auctions, Transmission Service Agreements and Local/Regional Network Services under tariff/rate agreements. Transmission services are provided as demanded by customers and represent a single performance obligation. The performance obligation is satisfied over time as the transmission services are provided by the Company. The Company records revenue based on the volumes delivered and the approved tariff rates.

Off system sales: Represents direct sales of gas to participants in the wholesale natural gas marketplace, which occur after customers' demands are satisfied. The performance obligation related to these off system sales is to deliver a quantity of gas at the delivery point which represents a single performance obligation that is satisfied over time.

Revenue from alternative revenue programs: The Company's regulated subsidiaries record revenues in accordance with accounting principles for rate-regulated operations for arrangements between the regulated subsidiaries and their respective regulators, which are not accounted for as contracts with customers. These primarily include programs that qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the regulated subsidiaries to adjust rates in the future, in response to past activities or completed events. The regulated subsidiaries' electric and gas 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 and unbilled revenue. Regulated subsidiaries' revenues reflect adjustments for the difference between allowed transmission recoveries and actual transmission revenue. In addition, the regulated subsidiaries have positive revenue adjustment mechanisms, such as earnings adjustment mechanisms related to the achievement of clean energy objectives and demand side management initiatives, as well as gas safety and reliability incentives. The Company recognizes revenue 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: Lease income that primarily includes electric generation revenue, which is derived from billings to LIPA for electric generation capacity and, to the extent requested, energy from the Company's existing oil and gas-fired generating plants. The arrangement is treated as an operating lease within the scope of the leasing standard, where Genco acts as lessor with rental income being recorded as other income, which forms part of total revenue. Lease payments (capacity payments) are recognized on a straight-line basis and variable lease payments are recognized as the energy is generated. Other transactions included consist of income from pole rentals, capital-related operations and maintenance billings 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 $359 million and $321 million for the years ended March 31, 2026 and 2025, respectively, within operations and maintenance expense in the accompanying consolidated statements of operations and comprehensive income. The activity in the allowance for doubtful accounts for the years ended March 31, 2026 and 2025 is as follows:

	Year Ended March 31, 2026 (in millions of dollars)		
	Utility Accounts Receivables	**Non-Utility Accounts Receivables**	**Total Allowance**
Beginning Balance	**$ 653**	**68**	**$ 721**
Credit loss expense	**336**	**15**	**351**
Write-offs	**(384)**	**(8)**	**(392)**
Recoveries	**81**	**5**	**86**
Ending Balance	**$ 686**	**80**	**$ 766**

	Year Ended March 31, 2025 (in millions of dollars)		
	Utility Accounts Receivables	**Non-Utility Accounts Receivables**	**Total Allowance**
Beginning Balance	$ 614	$ 67	$ 681
Credit loss expense	288	4	292
Write-offs	(318)	(8)	(326)
Recoveries	69	5	74
Ending Balance	$ 653	$ 68	$ 721

5. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. Regulatory deferrals are recorded by each legal entity as right of offset does not exist across the Company's regulated subsidiaries.

The following table presents the regulatory assets and regulatory liabilities recorded on the consolidated balance sheets:

	March 31,	
	2026	2025
	(in millions of dollars)	
Regulatory assets		
Current:		
Gas costs adjustment	**$ 329**	$ 224
Revenue decoupling mechanism	**179**	79
Residential assistance adjustment factor	**112**	8
Rate adjustment mechanisms	**73**	105
Renewable energy certificates	**50**	55
Transmission service	**47**	66
Smart Path Connect CWIP incentive	**36**	43
Clean Energy Standard	**22**	35
Other	**137**	89
Total	**$ 985**	$ 704
Non-current:		
Environmental response costs	**$ 3,156**	3,305
Postretirement benefits	**582**	316
Storm costs	**424**	919
Net metering deferral	**292**	322
Rate plan net regulatory asset	**262**	106
Property taxes	**220**	187
Exogenous events	**127**	180
Recovery of acquisition premium	**110**	118
Capital tracker	**107**	45
Arrears reduction	**99**	139
Other	**761**	651
Total	**$ 6,140**	$ 6,288

Regulatory liabilities		
Current:		
Energy efficiency	**$ 328**	386
Derivative instruments	**87**	73
Revenue decoupling mechanism	**104**	88
Rate adjustment mechanisms	**72**	257
Profit sharing	**58**	51
Other	**69**	69
Total	**$ 718**	924
Non-current:		
Cost of removal	**$ 2,195**	1,971
Postretirement benefits	**2,184**	1,457
Regulatory tax liability, net	**1,712**	1,820
Return on Equity Complaint	**343**	-
Energy efficiency	**299**	321
Carrying charges	**203**	228
Energy Highway - Section 70	**125**	117
Over/Under Rate Adjustment	**98**	-
Other	**660**	923
Total	**$ 7,819**	$ 6,837

Regulatory assets associated with future financial obligations that were deferred in accordance with orders issued by the NYPSC, DPU, and FERC 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 $398 million and $304 million, respectively.

Arrears reduction: This regulatory balance represents the deferral, net of recoveries, of the Arrears Reduction Program ("ARP") for Phase 1 and Phase 2. The NYPSC authorized recovery of the Phase 1 and Phase 2 regulatory assets over three and half years and eleven years, respectively, through a surcharge effectuated by a tariff filing. The authorized amounts being recovered include both the taxpayer funded portion and associated carrying charge.

Capital tracker: 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.

Carrying charges: The Company records carrying charges on regulatory balances for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund as approved, in accordance with the NYPSC. Carrying charges are not recorded on items for which expenditures have not yet been made.

Clean Energy Standard: Under the Clean Energy Standard ("CES") order issued by the NYPSC, the Company is required to purchase ZECs to support the New York's goal to reduce statewide greenhouse gas emissions. The Company defers the difference between the cost of the ZECs and the actual collections through the Clean Energy Standard Supply charge billed to retail commodity customers.

Cost of removal: The regulatory asset represents cumulative removal amounts spent, but not yet collected, to dispose of property, plant and equipment, while the regulatory liability represents cumulative removal amounts collected but not yet spent. The asset is reduced as the allowance for cost of removal is recovered in rates. The liability is discharged as removal costs are incurred.

Derivative instruments: As of March 31, 2026 and 2025, only derivative contracts at the regulated subsidiaries were subject to regulatory deferral. Derivative instruments are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs.

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. Also implemented was the demand response costs and non-labor demand response operations and maintenance cost ("DROM") surcharge, which allows the Company to recover non-labor operations and maintenance costs associated with their distribution level demand response programs on an annual lag.

Energy Highway - Section 70: The Company was authorized to lease certain existing transmission right-of-way to LS Power, New York Power Authority ("NYPA"), and Transco, and to transfer the transmission facilities to LS Power and Transco for their electric transmission upgrade project. The regulatory liability balance primarily represents the proceeds from the sale of assets, the lease of land and carrying charges at the pre-tax WACC rate.

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 former manufactured gas plant ("MGP") sites and related facilities. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation ("SIR") costs. Related insurance costs subject to recovery do not earn a return and are excluded from rate base. The recovery period is to be determined in future rate plans or other orders issued by the applicable state regulatory bodies.

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 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.

Gas costs adjustment: The Company is subject to rate adjustment mechanisms for commodity costs, whereby an asset or liability is recognized resulting from differences between billed revenues and the underlying cost being recovered, as approved by DPU and NYPSC. These amounts will be refunded to, or recovered from, customers over the next year with interest. Only regulatory assets related to the unbilled and commodity bad debt do not earn a return.

Net metering deferral: 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.

Over/Under rate adjustment: The Company defers costs to be recovered from customers through future rates. The over/under rate adjustment is a result of differences between billed and allowed recoverable costs. This difference is recovered from, or refunded to, customers on a two-year lag.

Postretirement benefits: The regulatory asset represents the Company's unamortized, non-cash accrual of net pension actuarial gains and losses in addition to actual costs associated with the Company's pension plans, in excess of amounts received in rates that are to be collected in future periods. The regulatory liability represents the Company's unamortized, non-cash accrual of net PBOP actuarial gains and losses in addition to excess amounts received in rates over actual costs of the Company's PBOP plans that are to be recovered from or passed back to customers in future periods. This regulatory balance does not earn a return. The recovery period is to be determined in future rate plans or other orders issued by the state regulators.

Property taxes: Keyspan Gas East, Brooklyn Union, and Niagara Mohawk's current rate plan continues the reconciliation of actual property and special franchise tax expenses to the rate allowance. A property tax regulatory asset or liability is recorded for the difference of 90% of actual property and special franchise tax expenses and the rate allowance, for future recovery from or refunded to customers. The 10% share above or below the level in rates is subject to a cap. The Companies are authorized to implement a surcharge/refund, limited to the annual recovery of two percent of its prior year's actual operating revenues, to recover from or refund to deferred property and special franchise taxes through the rate plan rate adjustment mechanism ("RAM").

Profit sharing: Represents a portion of deferred margins from off-system sale transactions. Under current rate orders, the Company is required to share in return 90% of margins earned from such optimization transactions to firm customers dependent on jurisdictions rate order. The amounts deferred on the balance sheet will be refunded to customers over the next twelve-month period.

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 actual revenues and the underlying cost being recovered, or differences between actual revenues and targeted amounts, as approved by the applicable state regulatory bodies. The rate related regulatory assets such as long-term contracting for renewable energy recovery ("LTCRER") and unbilled revenue do not earn a return.

Rate plan net regulatory asset: The net regulatory asset balance consists primarily of existing regulatory asset balances for storm costs, property taxes, environment response costs, carrying charges, and rate plan settlement deferral credit.

Recovery of acquisition premium: Represents the unrecovered amount (plus related taxes) by which the purchase price paid exceeded net book value in the 1998 acquisition of Colonial Gas Company by Eastern Enterprises, Inc. Eastern Enterprises, Inc. was owned by KeySpan Corporation ("KeySpan") at the time of NGUSA's acquisition of KeySpan in 2007. In exchange for certain rate concessions and the achievement of certain merger savings targets, the DPU has allowed Boston Gas (as the sole surviving entity from the legal consolidation of Boston Gas and Colonial Gas Company during the year-ended March 31, 2020) to recover the acquisition premium in rates, without interest, through August 2039.

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 Cut and Jobs Act of 2017 ("Tax Act").

Renewable energy certificates: Represents deferred costs associated with the Company's compliance obligations with Renewable Portfolio Standards ("RPS") in Massachusetts. The RPS is legislation 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 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, effective June 1, 2025. The recovery of the tiered discount program through RAAF began on March 1, 2026.

Revenue decoupling mechanism ("RDM"): As approved by the applicable state regulatory bodies, the Company has electric and gas RDMs which allow 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.

Return on Equity Complaint: On March 19, 2026, FERC issued an order lowering New England Power ("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.

Smart Path Connect CWIP incentive: As approved by FERC, the Company was granted an incentive in the form of recovery of prudently incurred transmission-related CWIP in rate base effective April 1, 2023 for the SPC transmission project with an actual in-service date of March 2026. See Note 6 "*Rate Matters*" for additional details.

Storm costs: The Company is allowed to recover qualifying storm costs from 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. These regulatory assets do not earn a return.

6. RATE MATTERS

Niagara Mohawk

General Rate Case

On April 25, 2025, Niagara Mohawk, DPS Staff and other settlement parties filed a Joint Proposal ("JP") for a three-year rate plan for Niagara Mohawk's electric and gas businesses beginning May 1, 2025 and ending March 31, 2028, which included an 11- month period in Rate Year One instead of the 12 months. On August 14, 2025, the NYPSC approved and adopted the three-year settlement through March 31, 2028 and supporting schedules for Niagara Mohawk's electric and gas businesses with limited additional requirements. To reduce rate volatility to customers over the term of the rate plan, the planned rate increases have been implemented on a levelized percentage basis of 3.4% and 5.5% in Rate Year 1, 5.6% and 5.5% in Rate Year 2, and 4.6% and 6.0% in Rate Year 3 for electric and gas delivery service, respectively. After taking into account the impact of levelization, the JP results in increases in delivery revenues for Niagara Mohawk of approximately $167 million and $57 million in Rate Year 1, $297 million and $65 million in Rate Year 2, and $243 million and $72 million in Rate Year 3 for electric and gas delivery service, respectively. Niagara Mohawk's revenue requirement for electric operations includes the amortization of a net electric regulatory asset balance as of December 31, 2023, totaling $187 million over a ten-year period.

The settlement is based upon a 9.5% ROE and a ratemaking capital structure reflecting a common equity component of 48%. The rate plans include an earnings sharing mechanism by which customers will share in earnings in excess of a 10% calculated return on equity for each rate year under the rate plan.

Pursuant to the JP, Niagara Mohawk recorded the Make Whole provision ("MWP") during the second quarter of fiscal year 2026. The MWP is intended to keep Niagara Mohawk in the same financial position it would have been in had rates been effective May 1, 2025.

Advanced Metering Infrastructure ("AMI")

On November 20, 2020, the NYPSC issued an order ("2020 AMI Order") which approved Niagara Mohawk's proposal for the deployment of AMI, also referred to as smart meters. In the approved rate case, Niagara Mohawk is authorized to recover $119 million of AMI-related operations and maintenance ("O&M") expense incurred during the six-year AMI deployment period beginning fiscal year 2022 subject to a downward-only reconciliation at the end of the six-year AMI deployment period. Likewise, the 2020 AMI Order established a capital expenditure cap for the program of approximately $475 million over the six-year AMI deployment period.

New York Transmission Projects

CLCPA Phase 2

On August 19, 2022, FERC accepted the New York Transmission Owners' (a group of New York electric utilities including Niagara Mohawk) Phase 2 Cost Sharing and Recovery Agreement ("CSRA"), which was developed to recover the costs of local transmission upgrades determined by the NYPSC to be necessary to meet New York's climate and renewable energy goals as required by the Climate Leadership and Community Protection Act ("CLCPA"). CSRA provides that the costs of NYPSC-approved local transmission upgrades will be shared statewide among the CLCPA's customers and recovered on a volumetric load-ratio basis. On February 16, 2023 the NYPSC issued an order authorizing Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Rochester Gas & Electric Corporation and Niagara Mohawk Power Corporation (the "Sponsoring Utilities") (i) to proceed with more than $4 billion of proposed transmission upgrades (with some modifications) and (ii) to seek recovery of associated costs through the previously approved CSRA. The order approved 100% of the approximately $2 billion in transmission upgrades proposed by Niagara Mohawk in the Northern New York and the Capital regions.

Smart Path Connect

On August 12, 2022, the NYPSC approved National Grid and NYPA filing seeking permission to construct and operate the Smart Path Connect ("SPC") project. SPC is a bulk transmission project jointly developed with NYPA in Northern New York. Niagara Mohawk's expected capital portion of the project, as specified in the FERC order approving Niagara Mohawk's filing, is approximately $535 million and will upgrade approximately 55 miles of an existing double circuit North-South transmission corridor from the Canadian border to central New York.

In July 2023, FERC approved the bulk of Niagara Mohawk's filing under Section 205 of the Federal Power Act. FERC's order approved Niagara Mohawk's request for an ROE of 10.3% for the SPC Project, a transmission incentive in the form of recovery of 100 percent of prudently incurred costs for CWIP in rate base, and the statewide cost allocation agreement for the SPC project all effective April 1, 2023. FERC's July 2023 order also found that Niagara Mohawk's proposed method of allocating General Plant and A&G expenses between the SPC project and the existing Transmission Service Charge raised an issue of material fact, and it set this single issue for hearing and settlement. Settlement filing was submitted to the NYISO on June 3, 2024. FERC approved the SPC settlement on August 8, 2024. As of March 31, 2026, construction was materially completed and Niagara Mohawk's portion of the line had been energized to 345 kV and was placed in-service on March 28, 2026.

The New York Gas Companies

Rate Case Filing

On May 29, 2026, the Brooklyn Union Gas Company and KeySpan Gas East Corporation (the "New York Gas Companies") filed a petition with the NYPSC seeking authorization to maintain current base delivery rates through March 31, 2028, effectively extending rates for an additional year beyond the term of the current rate plan (i.e. rates effective April 1, 2026 through March 31, 2027). The petition further proposes new and modified deferral mechanisms for certain non-controllable costs, as well as the introduction of a new surcharge beginning in fiscal year 2029 designed to recover costs deferred during the extension period. A decision on the petition is expected later this year.

General Rate Case

On August 15, 2024, the NYPSC approved and adopted a JP establishing a three-year rate plan for the Brooklyn Union Gas Company and KeySpan Gas East Corporation (the "New York Gas Companies" or the "Companies") beginning April 1, 2024, and ending March 31, 2027. To reduce rate volatility to customers over the term of the rate plan, the planned rate increases have been implemented on a levelized percentage basis, at an annual total bill increase of 10.5% for the Brooklyn Union Gas Company and 9.4% for KeySpan Gas East Corporation for each of the three rate years. After taking into account the impact of levelization, the JP results in increases in gas delivery revenues for the Brooklyn Union Gas Company and KeySpan Gas East Corporation of approximately $257 million and $147 million in Rate Year 1, $288 million and $163 million in Rate Year 2, and $320 million and $180 million in Rate Year 3, respectively. The Brooklyn Union Gas Company's revenue requirement includes the amortization of a net regulatory asset balance totaling $196 million over a ten-year period, while KeySpan Gas East Corporation's revenue requirement includes the amortization of a net regulatory asset balance totaling $41 million over a five-year period. The rate plans include an earnings sharing mechanism, where New York Gas Companies will share a portion of any earnings in excess of 9.9% with customers. The settlement is based upon a 9.4% ROE and a ratemaking capital structure that reflects a common equity component of 48% for the New York Gas Companies.

Pursuant to the JP, New York Gas Companies recorded a Make Whole provision ("MWP") during the second quarter of fiscal year 2025. The MWP is intended to keep The New York Gas Companies in the same financial position it would have been in had rates been effective April 1, 2024.

The Massachusetts Electric Companies

General Rate Case

On September 30, 2024, Massachusetts Electric 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 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 Infrastructure, Safety, Reliability, and Electrification ("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, Massachusetts Electric Company and Nantucket Electric filed their first annual PBR-O filing pursuant to their 2023 rate case. The filing requested a PBR adjustment of approximately $26 million, effective October 1, 2025, based on a PBR percentage of 4.7%. This amount includes $9 million for recovery of ongoing borderline service costs that were not included in Massachusetts Electric Company and Nantucket Electric's cost of service. As part of the filing, Massachusetts Electric Company and Nantucket Electric also sought recovery of $20 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 $18 million, while denying recovery of $9 million in ongoing borderline service costs included in the proposed adjustment, as well as disallowance of $20 million in prior period borderline costs.

On June 15, 2026, Massachusetts Electric Company and Nantucket Electric filed their second electric PBR-O filing, seeking DPU approval for an approximately $14 million rate adjustment based on a 2.8% PBR-O percentage.

Recovery of Transmission Costs

Massachusetts Electric 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 Massachusetts Electric Company, Massachusetts Electric 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, Massachusetts Electric 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. Massachusetts Electric Company recorded total receivables of $343 million, including $253 million recorded as an intercompany receivable from its affiliate, NEP, $70 million recorded in accounts receivable, net, and $20 million recorded in other noncurrent assets. The $343 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, Massachusetts Electric Company and Nantucket Electric made their GMP cost recovery filing for calendar year 2024, seeking to recover $34 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, Massachusetts Electric Company and Nantucket Electric made their GMP cost recovery filing for calendar year 2025, seeking to recover $56 million, including interest. The DPU approved the Massachusetts Electric Company and Nantucket Electric's proposed factors to recover the costs, subject to further investigation and reconciliation.

Advanced Metering Infrastructure

On March 14, 2025, Massachusetts Electric 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 $26 million, plus estimated interest for a total amount of $27 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, Massachusetts Electric Company and Nantucket Electric 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 million in additional investment over seven years would be required. Massachusetts Electric Company and Nantucket Electric supports AMI-based load settlement but stresses the costs are incremental and were not part of its approved AMI business case. Massachusetts Electric Company and Nantucket Electric 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, Massachusetts Electric Company and Nantucket Electric made their AMI cost recovery filing for calendar year 2025, seeking to recover $45 million, including interest. The DPU approved Massachusetts Electric Company and Nantucket Electric's proposed factors to recover the costs, subject to further investigation and reconciliation.

Storm Threshold Deferral Requests

On June 14, 2024, Massachusetts Electric Company and Nantucket Electric requested approval to defer $11 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 Massachusetts Electric Company and Nantucket Electric's Storm Fund Replenishment Factor ("SFRF"), subject to a prudency review in a future proceeding.

The DPU approved Massachusetts Electric Company and Nantucket Electric's request to defer $25 million of storm deductibles related to calendar years 2020 through 2022 for future recovery which was later updated to $19 million. On September 30, 2024, the DPU approved the recovery of $14 million through Massachusetts Electric Company and Nantucket Electric's SFRF in the D.P.U. 23-150 order.

Storm Cost Recovery

On May 31, 2024, Massachusetts Electric 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 million in O&M costs.

On June 30, 2025, Massachusetts Electric Company and Nantucket Electric submitted a prudency review to the DPU for $71 million incremental O&M associated with 14 storm fund-qualifying weather events which occurred between January 2023 and December 2023, and $67 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 Massachusetts Electric Company and Nantucket Electric'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 $86 million in O&M costs. On April 10, 2026, Massachusetts Electric Company and Nantucket Electric filed its compliance filings pursuant to the order with revised amounts for approval of $83M. Massachusetts Electric Company and Nantucket Electric are 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 Massachusetts Electric 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 Massachusetts Electric Company and Nantucket Electric'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 Massachusetts Electric Company and Nantucket Electric of $570 million for eligible investments.

Capital Investment Projects ("CIP")

On October 31, 2024, the DPU approved four CIPs Massachusetts Electric 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, Massachusetts Electric Company submitted a new CIP proposal under the extension of the PSPP established by the ESMP order, allocating approximately $39 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 Massachusetts Electric Company demonstrated good cause to continue constructing all four approved CIPs with cost recovery.

Solar Phase II and III

On August 30, 2024, Massachusetts Electric 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 million. The remaining Phase II and Phase III solar facilities were included for recovery through base distribution rates in D.P.U 23-150.

Massachusetts Electric 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 Massachusetts Electric Company and Nantucket Electric's recovery of $7 million in costs incurred in 2022 associated with Phase II and III Massachusetts Electric Company and Nantucket Electric 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 Massachusetts Electric Company and Nantucket Electric's recovery of $6 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, Massachusetts Electric Company and Nantucket Electric received final approval from the DPU to recover $6 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, Massachusetts Electric Company and Nantucket Electric filed a proposal with the DPU to recover $25 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, Massachusetts Electric Company, together with Nantucket Electric, filed with the DPU a proposal for Phase IV EV Program with a total budget of $194 million.

On May 15, 2026, Massachusetts Electric Company, together with Nantucket Electric, filed their annual filing for the recovery of $43 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. Massachusetts Electric 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 Program Administrators' ("PAs") three-year plans, with modifications, the most notable of which is a large reduction in budget of $500 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 million reduction. Massachusetts Electric Company and Nantucket Electric's updated budget for the next three years is $1.39 billion, inclusive of performance incentives. On February 27, 2026, Massachusetts Electric 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 Massachusetts Electric Company and Nantucket Electric's request on April 29, 2026.

Service Quality

On March 20, 2025, Massachusetts Electric Company filed proposals to refund $15 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. Massachusetts Electric 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 Massachusetts Electric 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 Massachusetts Electric Company's annual service quality report; the DPU approved the report without penalty.

Infrastructure, Safety, Reliability, and Electrification

Massachusetts Electric Company, together with Nantucket Electric, filed their first annual ISRE filing on June 13, 2025. The filing proposed to recover $22 million of incremental costs associated with Massachusetts Electric Company and Nantucket Electric'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.

On June 15, 2026, Massachusetts Electric Company and Nantucket Electric Company filed their second annual ISRE filing with the DPU seeking approval to recover a revenue requirement of $75 million associated with calendar year 2025 investments, effective October 1, 2026.

Department of Energy Resources ("DOER")

On March 4, 2025, Massachusetts Electric Company and Nantucket Electric received a request from the DOER to credit a sum of Alternative Compliance Payments collected by the DOER to Massachusetts Electric Company and Nantucket Electric's residential customers. As of March 31, 2025, Massachusetts Electric Company and Nantucket Electric recorded this as a receivable within other current assets, net and a liability within other current liabilities. Massachusetts Electric Company and Nantucket Electric received $61 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 Massachusetts Electric Company, 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 million (equivalent to about 15% bill reduction) funded directly by the Commonwealth of Massachusetts. On March 16, 2026, Massachusetts Electric 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 Massachusetts Electric Company and Nantucket Electric to recover the costs from customers between May 1, 2026, and December 31, 2026.

The Boston Gas Company

General Rate Case

On January 16, 2026, Boston Gas Company filed its gas rate case with the MA DPU for rates effective December 1, 2026. Boston Gas Company requested, among other things, an increase in distribution revenues by approximately $342M, including the transfer of recoverable revenue requirement totaling approximately $198M associated with GSEP investments placed in service between January 1, 2020 and December 31, 2024. Effectively, Boston Gas Company will see an incremental increase in base distribution revenue of $144M, or 12 percent, if approved as filed. Boston Gas Company is also requesting continuation of its performance-based ratemaking mechanism, a one-time LNG roll-in, and a DPU 220 C.M.R. 101 incremental requirements tracker.

The Department's notice of filing and procedural schedule were issued and the discovery process is under way, ending on May 22, 2026. Public hearings concluded on April 15, 2026. Evidentiary hearings will be held from June 29, 2026 to the end of July 2026, followed by briefings and an Order by the end of November 2026.

PBR Plan Filing

Boston Gas Company made its fourth annual PBR filing on June 13, 2025. The filing requested a PBR adjustment effective October 1, 2025, of approximately $41 million, based on a PBR percentage of 4.15%. On September 30, 2025, the DPU approved most of the filed PBR adjustments, totaling $40 million. Furthermore, the DPU approved an "exogenous event" for hiring full time employees because of the amendments to the pipeline safety regulations, and the proposed rate design and equalization of rates, but rejected changes to scorecard metrics.

On June 15, 2026, Boston Gas Company submitted its fifth annual PBR Plan filing, reporting scorecard results without proposing any changes to base distribution rates.

Gas System Enhancement Plan (GSEP)

On October 31, 2024, Boston Gas Company filed with the DPU its proposed GSEP for calendar year 2025, which included replacing or retiring 120 miles of leak-prone pipe ("LPP") and repairing an estimated 144 Grade 3 significant Environmental Impact leaks. On April 30, 2025, the DPU issued an Order approving Boston Gas Company's 2025 GSEP of $220 million and made several changes to GSEP, including a reduction of the annual recovery cap from 3.0% to 2.5%, to ensure affordability, safety prioritization, and compliance with the Commonwealth's climate objectives.

On May 1, 2025 Boston Gas Company filed its GSEP reconciliation ("GREC") filing, which reflects the final 2024 capital expenditures that produced revenue requirements of approximately $181 million. On October 31, 2025, the DPU approved Boston Gas Company's 2024 GREC, finding the infrastructure projects to be eligible and associated costs to be reasonable and prudent, with an overall accelerated pace of LPP replacement. The approved Gas System Enhancement Reconciliation Adjustment Factors ("GSERAFs"), effective November 1, 2025, were designed to recover $4 million for Boston. The DPU also allowed Boston Gas to defer $59 million above the revenue cap for future recovery.

On October 31, 2025, Boston Gas Company filed its calendar year 2026 GSEP Plan, which included replacing 90 miles of leak-prone pipe totaling $430 million. In its Plan, Boston Gas Company responds to the DPU's April 2024 Order directives by evaluating advanced leak repair technology, requesting an extended timeline for GSEP to 2050 due to the reduced cap, and proposing a revised tariff to allow for recovery of costs associated with exploring NPAs; however, Boston Gas Company is not requesting recovery of any NPA associated costs with this filing.

On April 30, 2026, the DPU approved National Grid's calendar year 2026 GSEP and its associated revenue requirements of$283 million for Boston Gas but lowered the revenue cap from 2.5% to 2.0% and continued the ban on carrying charges for deferred costs. Boston Gas Company's request to extend its remediation timelines to 2050 was denied, and it must maintain its existing 2034 and 2039 completion targets. The DPU approved the Risk Prioritization Guidelines over the LDCs' legal objections, though full compliance is not required until the 2027 GSEPs. The DPU also denied Boston Gas Company's proposed NPA-related tariff changes, and made clear it expects meaningful departures from business as usual in the 2027 filing.

On May 1, 2026, Boston Gas Company filed its calendar year 2025 GSEP Plan Reconciliation. Boston Gas Company abandoned approximately 95 miles of leak-prone pipe in 2025. The CY 2025 GSEP revenue requirements total approximately $240 million for Boston Gas. After application of the GSEP Cap, the reconciliation shows modest over-recoveries, and Boston Gas Company proposes to set GSERAFs to zero effective November 1, 2026, incorporating cumulative balances into revised GSEAFs effective January 1, 2027, concurrent with new base rates from the gas rate case. Finally, NPA analyses were conducted for 292 projects pursuant to the Department's Future of Gas Orders and none were deemed NPA-viable.

On May 20, 2026, Boston Gas Company filed an appeal with the Massachusetts Supreme Judicial Court challenging the DPU's D.P.U. 25-GSEP-03 Order, which denied Boston Gas Company's request to extend its GSEP Plan timeline and reduced the annual revenue recovery cap from 2.5% to 2.0%. The appeal argues the Order violates the GSEP Statute on multiple grounds and asks the Court to set it aside and remand for further proceedings.

Geothermal District Energy Demonstration Program

On December 15, 2021, the DPU approved Boston Gas Company's petition for a five-year, $15.6 million geothermal district energy demonstration program. The costs for the demonstration program are recovered through a factor in the Local Distribution Adjustment Factor ("LDAF"). Due to minimal costs incurred in calendar years 2022 and 2023, Boston Gas Company proposed to delay cost recovery until the July 1, 2025 filing, which the DPU approved on October 21, 2024. On July 1, 2025, Boston Gas Company filed its Annual Report and was authorized to recover incremental operating costs incurred for calendar years 2022, 2023, and 2024 associated with the demonstration program. Boston Gas Company chose two sites for the program in Lowell and Franklin Field, Boston, working with the Boston Housing Authority. Boston Gas Company has decided not to proceed with the Lowell site. Boston Gas Company received DPU approval of its program costs for calendar years 2022, 2023, and 2024 on October 29, 2025. Additionally, the DPU approved changes to the tariff to allow recovery of prudently incurred costs associated with the termination of projects under the program.

2026 Winter Bill Relief

The DPU approved a comprehensive winter bill relief program proposed by Boston Gas Company and its affiliates Massachusetts Electric Company and Nantucket Electric Company. The program will provide residential gas customers with a 10% reduction in total bills during the February and March 2026 billing cycles. This 10 percent reduction will be deferred and collected from customers during the off-peak period, between May and October 2026, through Boston Gas Company's LDAF filing, which was approved by the DPU on April 30, 2026.

Climate Compliance Plan

On April 1, 2025, Boston Gas Company filed its first Gas Climate Compliance Plan in accordance with the Future of Gas Orders. Boston Gas Company is requesting that the DPU approve a tariff to recover costs associated with implementing certain aspects of its NPA framework and provide a way to recover costs for other work not currently reflected in rates. On August 8, 2025, the DPU issued a revised draft proposal on gas line extensions, which would require connecting customers to pay the full cost to connect, with limited exception, noting that this proposal will be further litigated in the Climate Compliance Plan proceeding. Boston Gas Company responded to the DPU's proposal on gas line extensions, as well as Boston Gas Company's obligation to serve existing customers. Evidentiary hearings were conducted in March 2026 and briefing concluded on June 3, 2026.

2025-2027 Three-Year Energy Efficiency Plan

Refer to "2025-2027 Three-Year Energy Efficiency Plan" section under The Massachusetts Electric Companies.

In contrast to the Massachusetts Electric Companies, Boston Gas Company has requested a three-year budget totaling $965 million.

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 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 million reduction. Boston Gas Company's updated budget for the next three years is $823.0 million, inclusive of performance incentives. The DPU approved the compliance filing on June 30, 2025. Boston Gas Company recovers its costs through the Energy Efficiency Surcharge in its LDAF, which was approved by the Department on October 31, 2025 for rates through October 31, 2026. Boston Gas Company will file its 2026 LDAF by August 1, 2026.

NEP

Stranded Cost Recovery

Under the settlement agreements approved by state commissions and the FERC, NEP is permitted to recover stranded costs, which are costs associated with its former generating investments (nuclear and non-nuclear) and related contractual commitments that were not recovered through the sale of those investments. NEP earns an ROE related to stranded cost recovery consisting of nuclear-related investments. In Massachusetts, Rhode Island, and New Hampshire, the current ROEs are 9.20%, 10.46%, and 7.71%, respectively. NEP will recover its remaining non-nuclear stranded costs when decommissioning costs are complete.

New England Transmission Return on Equity ("ROE")

As of March 2026, the FERC resolved long-standing complaints in Docket No. EL11-66, which originally began in 2011 to challenge the base ROE of New England Transmission Owners ("NETOs"). NEP has been earning revenues at the existing 10.57% base ROE for more than a decade while the complaints have been unresolved. On March 19, 2026, FERC issued an order lowering NEP and the 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. On April 14, 2026, the FERC issued a notice to extend the deadline to complete the refund to May 20, 2027. NEP, along with other NETOs, sought rehearing of the March 19, 2026 order on April 20, 2026 with respect to issues related to the ROE methodology and the refund periods. NEP recorded total liabilities of $281 million, of which $253 million represents an intercompany payable to Massachusetts Electric Company MECO. This amount resulted in a $196 million reduction to revenue and $85 million of interest expense.

On April 30, 2026, the NETOs (including NEP) filed to increase the base ROE in the ISO-NE Open Access Transmission Tariff to 11.39%, using the methodology from the March 19th order with updated market data, effective June 30, 2026. A decision from the FERC is pending.

7. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes property, plant and equipment at cost and operating lease right-of-use assets, along with accumulated depreciation and amortization:

	March 31,	
	2026	2025
	(in millions of dollars)	
Plant and machinery	**$ 59,033**	$ 53,663
Assets in construction	**5,016**	4,891
Land and buildings	**2,893**	2,652
Software and other intangibles	**4,008**	3,351
Operating lease ROU assets	**1,536**	1,419
Total property, plant and equipment	**72,486**	65,976
Accumulated depreciation – Tangible assets	**(13,073)**	(12,234)
Accumulated amortization – Software and other intangibles	**(2,284)**	(1,936)
Accumulated amortization – Operating lease ROU assets	**(563)**	(526)
Property, plant and equipment, net	**$ 56,566**	$ 51,280

The Company capitalizes costs incurred during the application development stage of internal use software projects to property, plant and equipment. The Company amortizes capitalized software costs ratably over the expected lives of the software, primarily ranging from 3 to 10 years and commencing upon operational use. Amortization expense for capitalized software was $340 million and $297 million for the years ended March 31, 2026 and 2025, respectively. As of March 31, 2026, amortization expense is estimated to be $387 million, $342 million, $301 million, $262 million, and $198 million for 2027 through 2031, respectively.

8. DERIVATIVE INSTRUMENTS

The Company utilizes derivative instruments to manage commodity price risk associated with its natural gas and electricity purchases. The Company's commodity risk management strategy is to reduce fluctuations in firm gas and electricity sales prices to its customers.

The Company's financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company engages in risk management activities only in commodities and financial markets where it has an exposure, and only in terms and volumes consistent with its core business.

Notional Amounts

The notional contract amount represents the gross nominal value of the outstanding derivative contracts.

Volumes of outstanding commodity derivative instruments measured in dekatherms ("dths") and megawatts hour ("mwhs") are as follows:

	March 31,	
	2026	2025
	(in millions)	
Gas contracts (dths)	**179**	193
Electric contracts (mwhs)	**102**	14

Summary of Derivative Instruments on Consolidated Balance Sheets

The following tables reflect the gross and net amounts of the Company's derivative assets and liabilities as of March 31, 2026 and 2025.

	March 31, 2026 *(in millions of dollars)*				
	Gross amount of recognized assets (liabilities)	**Gross amount offset in the consolidated balance sheet**	**Net amount of assets (liabilities) presented in the consolidated balance sheet**	**Gross amount not offset on the consolidated balance sheet**	**Net amount**
	A	***B***	***C = A-B***	***D***	***E = C-D***
ASSETS:					
Other current assets, net					
Gas contracts	**$ 8**	**$ -**	**$ 8**	**$ 2**	**$ 6**
Electric contracts	**112**	**-**	**112**	**14**	**98**
Other non-current assets, net					
Gas contracts	**2**	**-**	**2**	**-**	**2**
Electric contracts	**79**	**-**	**79**	**24**	**55**
Total	**201**	**-**	**201**	**40**	**161**
LIABILITIES:					
Current liabilities					
Gas contracts	**16**	**-**	**16**	**2**	**14**
Electric contracts	**17**	**-**	**17**	**14**	**3**
Other non-current liabilities					
Gas contracts	**8**	**-**	**8**	**-**	**8**
Electric contracts	**41**	**-**	**41**	**24**	**17**
Total	**82**	**-**	**82**	**40**	**42**
Net assets (liabilities)	**$ 119**	**$ -**	**$ 119**	**$ -**	**$ 119**

	March 31, 2025				
	(in millions of dollars)				
	Gross amount of recognized assets (liabilities)	**Gross amount offset in the consolidated balance sheet**	**Net amount of assets (liabilities) presented in the consolidated balance sheet**	**Gross amount not offset on the consolidated balance sheet**	**Net amount**
	A	***B***	***C = A-B***	***D***	***E = C-D***
ASSETS:					
Other current assets, net					
Gas contracts	$ 34	$ -	$ 34	$ -	$ 34
Electric contracts	83	-	83	12	71
Other non-current assets, net					
Electric contracts	16	-	16	14	2
Total	133	-	133	26	107
LIABILITIES:					
Current liabilities					
Gas contracts	1	-	1	-	1
Electric contracts	13	-	13	12	1
Other non-current liabilities					
Gas contracts	7	-	7	-	7
Electric contracts	39	-	39	14	25
Total	60	-	60	26	34
Net assets (liabilities)	$ 73	$ -	$ 73	$ -	$ 73

Effect of Derivative Instruments on Statements of Operations and Comprehensive Income

Changes in fair value of the Company's rate recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, changes in the fair value of those contracts do not affect earnings. Realized gains or losses on the settlement of the Company's commodity derivative contracts are refunded to, or collected from, customers consistent with regulatory requirements.

The following table summarizes amounts recognized in earnings for commodity derivative instruments not designated as hedging instruments for the years ended March 31, 2026 and 2025:

		Year Ended March 31,	
	Location	**2026**	2025
		(in millions of dollars)	
Electric contracts	Purchased electricity	$ (181)	$ 6
Gas contracts	Purchased gas	28	(31)
Total gains (losses) recognized in earnings		**$ (153)**	$ (25)

The following table summarizes the accumulated changes in the fair value of commodity derivative instruments not designated as hedging instruments that have been deferred as regulatory assets and liabilities for the years ended March 31, 2026 and 2025:

	Location	Year Ended March 31,			
		2026		2025	
		(in millions of dollars)			
Electric contracts	Regulatory asset/(liability)	**$**	**(133)**	$	(47)
Gas contracts	Regulatory asset/(liability)		**14**		(26)
Total changes in regulatory assets (liabilities)		**$**	**(119)**	$	(73)

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price. Credit risk represents the risk of loss due to counterparty non-performance. Credit risk is managed by assessing each counterparty's credit profile and negotiating appropriate levels of collateral and credit support.

The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduces its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty.

Commodity Transactions

The Company enters into commodity transactions on the NYMEX. The NYMEX clearing houses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on the NYMEX are significantly collateralized and have limited counterparty credit risk.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to the Board, which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. NGUSA's Energy Procurement Risk Management Committee ("EPRMC") is responsible for approving transaction strategies, annual supply plans, and counterparty credit approval, as well as all valuation and control procedures. The EPRMC is chaired by the Head of Treasury Risk and Operations, and reports to both the NGUSA Board of Directors and the Finance Committee.

The EPRMC monitors counterparty credit exposure and appropriate measures are taken to bring such exposures below the limits, including, without limitation, netting agreements, and limitations on the type and tenor of trades. In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, the Company may limit its credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support, and negotiating the early termination of certain agreements. Similarly, the Company may be required to post collateral to its counterparties.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position as of March 31, 2026 and 2025 was $0 and $4 million, respectively. The Company had no collateral posted for these instruments as of March 31, 2026 and 2025, respectively. At March 31, 2026, if the Company's credit rating were to be downgraded by one, two, or three levels, it would be required to post additional collateral to its counterparties of $1 million, $8 million, or $16 million, respectively. At March 31, 2025, if the Company's credit rating had been downgraded by one, two, or three levels, it would have been required to post additional collateral to its counterparties of $0, $7 million, or $9 million, respectively. The counterparties had $31 million and $16 million of collateral posted to the Company as of March 31, 2026 and 2025, respectively.

Financing Transactions

The credit policy for financing transactions is managed by a central treasury department under policies approved by the Audit & Risk Committee. In accordance with these treasury policies, counterparty credit exposure utilizations are monitored daily against the counterparty credit limits. Counterparty credit ratings and market conditions are reviewed continually with limits being revised and utilization adjusted, if appropriate. Management does not expect any significant losses from non-performance by these counterparties.

9. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the consolidated balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2026 and 2025:

	March 31, 2026			
	Level 1	**Level 2**	**Level 3**	**Total**
	(in millions of dollars)			
Assets:				
Derivative instruments				
Gas contracts	**$ -**	**$ 2**	**$ 8**	**$ 10**
Electric contracts	**-**	**145**	**46**	**191**
Financial instruments				
Securities	**8**	**196**	**-**	**204**
Total	**8**	**343**	**54**	**405**
Liabilities:				
Derivative instruments				
Gas contracts	**-**	**15**	**8**	**23**
Electric contracts	**-**	**57**	**1**	**58**
Total	**-**	**72**	**9**	**81**
Net assets (liabilities)	**$ 8**	**$ 271**	**$ 45**	**$ 324**

	March 31, 2025			
	Level 1	Level 2	Level 3	Total
	(in millions of dollars)			
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 35	$ -	$ 35
Electric contracts	-	97	1	98
Financial instruments				
Securities	12	204	-	216
Total	12	336	1	349
Liabilities:				
Derivative instruments				
Gas contracts	-	1	8	9
Electric contracts	-	50	1	51
Total	-	51	9	60
Net assets (liabilities)	$ 12	$ 285	$ (8)	$ 289

Derivative Instruments:

The Company's Level 2 fair value derivative instruments primarily consist of financial over the counter ("OTC") gas swap contracts, OTC gas options, OTC power swap options, and physical gas purchase contracts with pricing inputs obtained from the NYMEX and the Intercontinental Exchange ("ICE"), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. The Company uses the Black Scholes option pricing formula that is built into the model to price all financial options. All model inputs (underlying forward prices, discount rates and volatilities) use market observable information. The Company may utilize discounting based on quoted interest rate curves, including consideration of non-performance risk, and may include a liquidity reserve calculated based on bid/ask spreads for the Company's Level 2 derivative instruments. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market-observable curves with correlation coefficients of 95% or higher.

The Company's Level 3 fair value derivative instruments primarily consist of physical gas option and renewable electric purchase contracts, which are valued based on internally developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries, are used for valuing such instruments. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks, such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3, as the model inputs generally are not observable. The Company considers non-performance risk and liquidity risk in the valuation of derivative instruments categorized in Level 2 and Level 3. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated, or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made.

Gas and Electric Contracts

The significant unobservable inputs used in the fair value measurement of the Company's gas purchase derivative instruments are forward curves and unobservable basis points. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

The significant unobservable inputs used in the fair value measurement of the Company's electric purchase derivative instrument are future energy prices derived from forward electricity bid curves. 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 table below provides a reconciliation of the beginning and ending balance for the Company's derivative instruments – gas and electric contracts, for which the Company elected the fair value option. 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 *(in thousands of dollars)*
Beginning balance	**$ (8)**
Net unrealized gains	**99**
Settlements	**(47)**
Net asset / (liability)	**$ 44**

Financial Investments - Securities

Securities are included in financial investments on the consolidated balance sheets and primarily include debt investments based on quoted market prices (Level 1) and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

Debt Securities

The following table sets forth the amortized cost and fair value of the Company's available-for-sale debt securities.

	Longest maturity date	Amortized Cost		Fair Value	
		March 31,			
		2026	2025	**2026**	2025
		(in millions of dollars)			
Rabbi Trust municipal bonds	2064	**$ 180**	$ 195	**$ 176**	$ 188
Niagara Mohawk municipal bonds	2065	**20**	16	**20**	16
		$ 200	$ 211	**$ 196**	$ 204

The gains and losses recorded in earnings or other comprehensive income in relation to available-for-sale debt securities were immaterial for the years ended March 31, 2026 and 2025. No other than temporary impairments were recorded in earnings or other comprehensive income during the years ended March 31, 2026 and 2025.

10. EMPLOYEE BENEFITS

The Company sponsors several qualified and non-qualified non-contributory defined benefit plans (the "Pension Plans") and post-retirement benefits other than pension (PBOP) plans (together with the Pension Plan (the "Plans")), covering substantially all employees.

The Company's regulated subsidiaries have regulatory recovery of virtually all of these costs and therefore have recorded related regulatory assets (liabilities) on the consolidated balance sheets. The Company records amounts for its unregulated subsidiaries to AOCI on the consolidated balance sheets.

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.

Pension Plans

The Pension Plans are defined benefit plans which provide union employees, as well as non-union employees with a retirement benefit. For non-union employees, the plans were closed to new entrants as of December 31, 2010. Non-union employees hired on or after January 1, 2011 are provided with a defined contribution plan. For union employees, the plans were closed, with one exception, to new entrants at varying dates from December 31, 2010 through June 2, 2019. Union employees hired on or after the closing of the pension plans to new entrants are provided with a defined contribution plan. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2026 and 2025, the Company made contributions of approximately zero and $10 million, respectively, to the qualified pension plans. The Company expects to contribute $12 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 and 2025 were approximately $518 million and $358 million, respectively. Benefit payments for the year ended March 31, 2026 included payments for an annuity contract purchase.

In February 2026, the Company agreed to purchase a group annuity contract that transferred approximately $595 million of pension obligations and related plan assets to an insurance company. This transaction resulted in the company recording a settlement gain of $22 million.

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 and 2025, the Company made contributions of zero and $171 million, respectively, to the PBOP plans. The Company contributions for the year ended March 31, 2025 included a nonrecurring contribution. The Company expects to contribute $13 million 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 and 2025 were approximately $188 million and $215 million, respectively.

Net Periodic Benefit Costs

The Company's net periodic pension (benefit) cost for the years ended March 31, 2026 and 2025 was ($45) million and $2 million, respectively. This included non-service pension benefits for the years ended March 31, 2026 and 2025 of ($133) million and ($88) million, respectively.

The Company's net periodic PBOP benefit was ($273) million and ($132) million for the years ended March 31, 2026 and 2025, respectively. This included non-service PBOP benefits for the years ended March 31, 2026 and 2025 of ($312) million and ($167) million, respectively.

Amounts Recognized in AOCI and Regulatory Assets/Liabilities

The following tables summarize other pre-tax changes in plan assets and benefit obligations recognized primarily in regulatory assets/liabilities and AOCI for the years ended March 31, 2026 and 2025:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2026	2025	**2026**	2025
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 110**	$ (8)	**$ (632)**	$ (122)
Reversal of net actuarial gain from settlements	**22**	-	**-**	-
Amortization of net actuarial (loss) gain	**(9)**	(46)	**215**	116
Amortization of prior service cost, net	**(4)**	(5)	**-**	-
Total	**$ 119**	$ (59)	**$ (417)**	$ (6)
Change in regulatory assets or liabilities	**$ 111**	$ (37)	**$ (361)**	$ (16)
Change in AOCI	**8**	(22)	**(56)**	10
Total	**$ 119**	$ (59)	**$ (417)**	$ (6)

The Company's regulated subsidiaries have regulatory recovery of these obligations and therefore amounts are included in regulatory assets/liabilities on the consolidated balance sheets. Costs of non-regulated subsidiaries are recorded as part of AOCI on the consolidated balance sheets.

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

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

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2026	2025	**2026**	2025
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 393**	$ 270	**$ (1,428)**	$ (1,012)
Prior service cost	**20**	24	**-**	-
Total	**$ 413**	$ 294	**$ (1,428)**	$ (1,012)
Included in regulatory assets (liabilities)	**$ 402**	$ 291	**$ (1,267)**	$ (906)
Included in AOCI	**11**	3	**(161)**	(106)
Total	**$ 413**	$ 294	**$ (1,428)**	$ (1,012)

Amounts Recognized on the Consolidated Balance Sheets

The following table summarizes the portion of the funded status that is recognized on the Company's consolidated balance sheets at March 31, 2026 and 2025:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2026	2025	**2026**	2025
	(in millions of dollars)			
Projected benefit obligation	**$ (5,501)**	$ (6,023)	**$ (2,357)**	$ (2,870)
Fair value of plan assets	**6,118**	6,690	**3,620**	3,433
Total	**$ 617**	$ 667	**$ 1,263**	$ 563
Non-current assets	**$ 863**	$ 920	**$ 1,365**	$ 860
Current liabilities	**(24)**	(24)	**(2)**	(2)
Non-current liabilities	**(222)**	(229)	**(100)**	(295)
Total	**$ 617**	$ 667	**$ 1,263**	$ 563

The benefit obligation shown above is the projected benefit obligation ("PBO") for the Pension Plans and the accumulated postretirement benefit obligation ("APBO") for the PBOP Plans. The Company is required to reflect the funded status of its Pension Plans above in terms of the PBO, which is higher than the accumulated benefit obligation ("ABO"), because the PBO includes the impact of expected future compensation increases on the pension obligation. The Pension Plans had ABO balances that did not exceed the fair value of plans assets as of March 31, 2026. The aggregate ABO balances for the Pension Plans were $5.3 billion and $5.8 billion as of March 31, 2026 and 2025, respectively.

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 gain for Pension was primarily driven by an increase in discount rate, partially offset by actual asset returns that were less than expected. The net actuarial gains for the PBOP Plans were 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 and an increase in the prescription drug trend assumption.

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):

(in millions of dollars) **Years Ended March 31,**	**Pension Plans**	**PBOP Plans**
2027	$ 359	$ 153
2028	371	157
2029	382	161
2030	393	163
2031	399	166
2032-2036	2,064	841
Total	$ 3,968	$ 1,641

Assumptions Used for Employee Benefits Accounting

	Pension Plans		**PBOP Plans**	
	Years Ended March 31,		**Years Ended March 31,**	
	2026	2025	**2026**	2025
Benefit Obligations:				
Discount rate	**5.60%**	5.50%	**5.60%**	5.50%
Rate of compensation increase (non-union)	**4.30%**	4.30%	**N/A**	N/A
Rate of compensation increase (union)	**4.70%**	4.70%	**N/A**	N/A
Weighted-average interest crediting rate for cash balanced plans	**6.00%**	5.65%	**N/A**	N/A
Net Periodic Benefit Costs:				
Discount rate	**5.45%-5.50%**	5.15%	**5.50%**	5.15%
Rate of compensation increase (non-union)	**4.30%**	4.30%	**N/A**	N/A
Rate of compensation increase (union)	**4.70%**	4.70%	**N/A**	N/A
Expected return on plan assets	**6.25% - 7.00%**	5.75% - 6.75%	**6.50% - 6.75%**	6.00% - 6.50%
Weighted-average interest crediting rate for cash balanced plans	**5.65%**	4.80%	**N/A**	N/A

For the year ended March 31, 2026, the discount rate used for remeasuring the annual pension expense and obligation for the purchase of the group annuity contract was 5.45%.

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 both on 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 the 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 trusteed 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, trusteed, employee life insurance and medical benefit plan sponsored by the Company. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of the Company.

The Company 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 contribution and expense 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, real estate, infrastructure 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:

	National Grid Pension		Union PBOP Plans		Non-Union PBOP Plans	
	March 31,		March 31,		March 31,	
	2026	2025	**2026**	2025	**2026**	2025
Equity	**5%**	6%	**15%**	15%	**67%**	67%
Diversified Alternatives	**1%**	2%	**5%**	5%	**0%**	0%
Fixed Income Securities	**70%**	70%	**80%**	80%	**33%**	33%
Private Equity	**13%**	12%	**0%**	0%	**0%**	0%
Real Estate	**4%**	4%	**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:

	March 31, 2026				
	Level 1	Level 2	Level 3	Not Categorized	Total
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	$ -	$ -	$ -	$ 315	$ 315
Diversified Alternatives	-	-	-	70	70
Corporate Bonds	-	2,238	-	455	2,693
Government Securities	28	1,454	-	611	2,093
Private Equity	-	-	-	811	811
Real Estate	-	-	-	216	216
Infrastructure	-	-	-	405	405
Total assets	$ 28	$ 3,692	$ -	$ 2,883	$ 6,603
Pending Transactions					(485)
Total net assets					$ 6,118
PBOP assets:					
Investments					
Equity	$ 48	$ -	$ -	$ 732	$ 780
Diversified Alternatives	160	-	-	-	160
Corporate Bonds	-	1,621	-	210	1,831
Government Securities	56	681	-	1	738
Insurance Contracts	-	-	-	245	245
Total assets	$ 264	$ 2,302	$ -	$ 1,188	$ 3,754
Pending Transactions					(134)
Total net assets					$ 3,620

	March 31, 2025				
	Level 1	Level 2	Level 3	Not Categorized	Total
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	$ 2	$ -	$ -	$ 355	$ 357
Diversified Alternatives	-	-	-	99	99
Corporate Bonds	-	2,539	-	504	3,043
Government Securities	19	1,554	-	603	2,176
Private Equity	-	-	-	791	791
Real Estate	-	-	-	253	253
Infrastructure	-	-	-	397	397
Total assets	$ 21	$ 4,093	$ -	$ 3,002	$ 7,116
Pending Transactions					(426)
Total net assets					$ 6,690
PBOP assets:					
Investments					
Equity	$ 41	$ -	$ -	$ 674	$ 715
Diversified Alternatives	133	-	-	-	133
Corporate Bonds	-	1,748	-	55	1,803
Government Securities	55	484	-	1	540
Insurance Contracts	-	-	-	211	211
Total assets	$ 229	$ 2,232	$ -	$ 941	$ 3,402
Pending Transactions					31
Total net assets					$ 3,433

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

The Company has two defined contribution pension plans that cover substantially all employees. For the years ended March 31, 2026 and 2025, the Company recognized an expense in the accompanying consolidated statements of operations and comprehensive income of $146 million and $133 million, respectively.

11. DEBT AND CREDIT FACILITIES

Total long-term debt for the Company at March 31, 2026 and 2025 is as follows:

			March 31,	
			2026	2025
			(in millions of dollars)	
Long-term debt:	Interest Rate	Maturity Date		
Brooklyn Union Unsecured Notes:				
Senior Note	3.41%	March 10, 2026	**$ -**	$ 500
Senior Note	4.63%	August 5, 2027	**400**	400
Senior Note	3.87%	March 4, 2029	**550**	550
Senior Note	4.87%	August 5, 2032	**400**	400
Senior Note	6.39%	September 15, 2033	**400**	400
Senior Note	6.39%	September 15, 2033	**150**	150
Senior Note	5.46%	March 16, 2036	**500**	-
Senior Note	4.50%	March 10, 2046	**500**	500
Senior Note	4.27%	March 15, 2048	**650**	650
Senior Note	4.49%	March 4, 2049	**450**	450
Senior Note	6.42%	July 18, 2054	**450**	450
Senior Note	6.42%	July 18, 2054	**200**	-
Brooklyn Union Notes			**$ 4,650**	$ 4,450

KeySpan Gas East Unsecured Notes:				
Senior Note	2.74%	August 15, 2026	**$ 700**	$ 700
Senior Note	5.99%	March 6, 2033	**500**	500
Senior Note	5.82%	April 1, 2041	**500**	500
Senior Note	3.59%	January 18, 2052	**400**	400
KeySpan Gas East Notes			**$ 2,100**	$ 2,100
Boston Gas Unsecured Notes:				
Senior Note	3.15%	August 1, 2027	**$ 500**	$ 500
Senior Note	3.13%	October 5, 2027	**150**	150
Senior Note	3.00%	August 1, 2029	**500**	500
Senior Note	3.76%	March 16, 2032	**400**	400
Senior Note	5.84%	January 10, 2035	**500**	500
Senior Note	4.49%	February 15, 2042	**500**	500
Senior Note	4.63%	March 15, 2042	**25**	25
Senior Note	6.12%	July 20, 2053	**400**	400
Boston Gas Medium-Term Notes:				
MTN Series 1995 C	7.25%	October 1, 2025	**-**	20
MTN Series 1995 C	7.25%	October 1, 2025	**-**	5
Boston Gas Notes			**$ 2,975**	$ 3,000
National Grid USA MTN	8.00%	November 15, 2030	**$ 250**	$ 250
National Grid USA Unsecured Notes:				
Senior Note	5.88%	April 1, 2033	**$ 150**	$ 150
Senior Note	5.80%	April 1, 2035	**307**	307
National Grid USA Notes			**$ 707**	$ 707
Niagara Mohawk Unsecured Notes:				
Senior Note	4.28%	December 15, 2028	**$ 500**	$ 500
Senior Note	1.96%	June 27, 2030	**600**	600
Senior Note	4.65%	October 3, 2030	**500**	-
Senior Note	2.76%	January 10, 2032	**400**	400
Senior Note	5.29%	January 17, 2034	**500**	500
Senior Note	4.28%	October 1, 2034	**400**	400
Senior Note	5.11%	January 12, 2036	**650**	-
Senior Note	4.12%	November 28, 2042	**400**	400
Senior Note	3.03%	June 27, 2050	**500**	500
Senior Note	5.78%	September 16, 2052	**500**	500
Senior Note	5.66%	January 17, 2054	**700**	700
Senior Note	6.00%	July 3, 2055	**750**	-
Senior Note	6.00%	July 3, 2055	**350**	-
Niagara Mohawk Notes			**$ 6,750**	$ 4,500

Massachusetts Electric Unsecured Notes:				
Senior Note	1.73%	November 24, 2030	**$ 500**	$ 500
Senior Note	5.90%	November 15, 2039	**800**	800
Senior Note	4.00%	August 15, 2046	**500**	500
Senior Note	5.87%	February 26, 2054	**400**	400
Massachusetts Electric Notes:			**$ 2,200**	$ 2,200
New England Power Unsecured Notes:				
Senior Note	3.80%	December 5, 2047	**$ 400**	$ 400
Senior Note	2.81%	October 6, 2050	**400**	400
Senior Note	5.94%	November 25, 2052	**300**	300
Senior Note	5.85%	September 8, 2055	**350**	-
New England Power Notes:			**$ 1,450**	$ 1,100
Total Notes Payable			**$ 20,832**	$ 18,057
NG Generation LLC Promissory Notes to NGNA	3.13% - 3.25%	June 2027 - April 2028	**$ 48**	$ 66
Boston First Mortgage Bonds	7.12%	April 2028	**$ 20**	$ 50
NIMO State Authority Financing Bonds	3.42% - 3.48%	December 2026 – July 2029	**$ 279**	$ 354
State Authority Financing Bonds	Variable	December 2027 – August 2042	**$ 117**	$ 117
Total debt			**$ 21,296**	$ 18,644
Unamortized debt premium (discount), net			**8**	-
Unamortized debt issuance costs			**(90)**	(78)
Current portion of long-term debt			**(788)**	(648)
Total long-term debt			**$ 20,426**	$ 17,918

The aggregate maturities of long-term debt for the years subsequent to March 31, 2026 are as follows:

(in millions of dollars) **March 31,**	**Maturities of Long-Term Debt**
2027	$ 788
2028	1,186
2029	1,124
2030	615
2031	1,850
Thereafter	15,733
Total	**$ 21,296**

The Company's debt agreements and banking facilities contain 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. The Company's subsidiaries also have restrictions on the payment of dividends which relate to their debt-to-equity ratios. As of March 31, 2026 and 2025, the Company was in compliance with all such covenants.

Significant Debt Facilities

State Authority Financing Bonds

At March 31, 2026, the Company had outstanding $396 million of State Authority Financing Bonds, of which $345 million were issued through the New York State Energy Research and Development Authority (“NYSERDA”) and the remaining $51 million were issued through the Massachusetts Development Finance Agency (“MDFA”), for the subsidiaries listed below.

Niagara Mohawk had outstanding $279 million of tax-exempt revenue bonds issued by the NYSERDA in a fixed rate interest mode ranging from 3.42% to 3.48%.

Revolving Credit Agreements

At March 31, 2026, the Company, NGNA, and the Parent 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. At March 31, 2026, these facilities have not been drawn against and can be used to fund the money pool.

The facilities are comprised of two distinct and separate single currency tranches, namely a Great Britain Pound (“GBP”) tranche of £2.1 billion, and a United States Dollar (“USD”) tranche of $4.0 billion. The Company, NGNA, and the Parent can all draw on these facilities, but the cumulative borrowings cannot exceed the GBP and USD tranche limits. The current annual commitment fees are 0.14%. The terms of the facilities restrict the borrowing of all subsidiaries of the Company to $45 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which the Company is obliged to meet. At March 31, 2026 and 2025, the Company, NGNA, and the Parent were in compliance with all covenants.

In August 2009, the Company entered into an agreement with the Parent, whereby either party can collectively borrow up to $3.0 billion from time to time for working capital needs, including funding of the regulated money pool, if necessary. In October 2024, the Company entered into a variation agreement to increase the borrowing limit from $3.0 billion to $5.0 billion until September 30, 2025. After the variation agreement ended, the borrowing limit reverted back to $3.0 billion. At March 31, 2026 and 2025, the Company had $1.8 billion and zero advances under this agreement, respectively. See Note 16, “*Related Party Transactions*” for additional details.

In August 2008, the Company entered into an agreement with NGNA, whereby the Company can borrow up to $1.5 billion from time to time for working capital needs. The latest amendment was made in March 2025 to increase the borrowing capacity to $16.0 billion. See Note 16, “*Related Party Transactions*” for additional details.

Debt Authorizations

Niagara Mohawk

Niagara Mohawk has regulatory approval from the FERC to issue up to $1.0 billion of short-term debt internally or externally. The authorization was renewed with an effective date of October 15, 2024 and expires on October 14, 2026. Niagara Mohawk had no external short-term debt as of March 31, 2026 and 2025.

On June 12, 2025, the NYPSC authorized Niagara Mohawk to issue up to $3.3 billion of new long-term debt securities through March 31, 2028. In addition, the NYPSC authorized Niagara Mohawk to issue debt to redeem approximately $29 million of preferred stock, if it is economical and in the best interest of customers.

Under this most recent authorization, Niagara Mohawk has issued $2.25 billion of long-term debt as of March 31, 2026.

Brooklyn Union

On August 14, 2025, the NYPSC authorized Brooklyn Union to issue up to $1.8 billion of new long-term debt securities, with the authorization valid for a period beginning on the effective date of the commission's order and ending on March 31, 2029. Under this most recent authorization, on March 16, 2026, Brooklyn Union issued $500 million and $200 million of unsecured long-term debt at a fixed rate of 5.46% and 6.42% with a maturity date of March 16, 2036 and July 18, 2054, respectively. The remaining authorization capacity is $1.1 billion as of March 31, 2026.

KeySpan Gas East

On August 14, 2025, the NYPSC authorized KeySpan Gas East to issue up to $1.5 billion of new long-term debt securities, with the authorization valid for a period beginning on the effective date of the commission's order and ending on March 31, 2029. Under this most recent authorization, KeySpan Gas East has issued no long-term debt as of March 31, 2026.

Boston Gas

On January 10, 2025, Boston Gas issued $500 million of unsecured long-term debt at 5.84% with a maturity date of January 10, 2035.

On April 21, 2026, the DPU authorized Boston Gas to issue up to $2.0 billion of new long-term debt securities through April 21, 2029.

Massachusetts Electric

Massachusetts Electric has regulatory approval from the FERC to issue up to $750 million of short-term debt internally or externally that expires on October 14, 2026. Massachusetts Electric had no external short-term debt as of March 31, 2026 and 2025.

On July 17, 2023, Massachusetts Electric 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, Massachusetts Electric has issued $900 million of long-term debt as of March 31, 2026 and 2025, respectively.

On February 5, 2026, Massachusetts Electric 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, Massachusetts Electric has issued no long-term debt as of March 31, 2026.

NEP

NEP has regulatory approval from the FERC to issue up to $1.5 billion of short-term debt. The authorization was renewed with an effective date of October 15, 2024 and expires on October 14, 2026. NEP had no external short-term debt as of March 31, 2026 and 2025.

On April 17, 2025, NEP received approval from the DPU to issue up to $1.2 billion of long-term debt in one or more transactions through April 17, 2028. In addition, NEP received approval for its petition from Vermont Public Service Board effective March 3, 2028 and New Hampshire Public Utilities Commission effective May 5, 2028. On September 3, 2025, NEP issued $350 million of unsecured long-term debt at 5.85% with a maturity date of September 8, 2055.

Genco

Genco has regulatory approval from the FERC to issue up to $250 million of short-term debt. The authorization was renewed with an effective date of October 15, 2024 and expires on October 14, 2026. Genco had no short-term debt as of March 31, 2026 and 2025.

12. INCOME TAXES

Components of Income Tax Expense (Benefit)

	Years Ended March 31,	
	2026	2025
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ (23)**	$ 58
State	**(18)**	(10)
Total current tax expense (benefit)	**(41)**	48
Deferred tax expense:		
Federal	**308**	135
State	**168**	144
Total deferred tax expense	**476**	279
Amortized investment tax credits [1]	**(3)**	(3)
Total deferred tax expense	**473**	276
Total income tax expense	**$ 432**	$ 324

[1] Investment tax credits ("ITC") are accounted for using the deferral and gross up method of accounting and 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 and 2025 are 22.5% and 18.9%, respectively. The following table presents a reconciliation of income tax expense (benefit) at the federal statutory tax rate of 21% to the actual tax expense:

	Years Ended March 31,			
	2026		2025	
	(in millions of dollars)			
	Amount	**Percentage**	Amount	Percentage
US Federal Income Tax	**$ 404**	**21.0%**	$ 360	21.0%
State and local income tax, net of federal benefit [2]	**114**	**5.9%**	100	5.8%
Tax credits	**(11)**	**-0.6%**	(6)	-0.4%
Changes in unrecognized tax benefits	**9**	**0.5%**	8	0.5%
Other Adjustments				
Amortization of excess deferred income taxes	**(62)**	**-3.2%**	(111)	-6.5%
Allowances for equity funds used during construction	**(18)**	**-0.9%**	(16)	-0.9%
Other	**(4)**	**-0.2%**	(11)	-0.6%
Effective Income Tax Rate	**$ 432**	**22.5%**	$ 324	18.9%

[2] State taxes of New York and 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 U.S. domestic operations.

The Company is included in the NGNA and subsidiaries consolidated federal income tax return, and New York and Massachusetts unitary state income tax returns. 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% 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
	(in millions of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	**$ 206**	$ 194
Environmental remediation costs	**855**	864
Net operating losses	**382**	255
Postretirement benefits	**139**	165
Regulatory liabilities	**1,714**	1,580
Reserves not currently deducted	**374**	320
Corporate alternative minimum tax credit	**7**	150
Other items	**355**	309
Total deferred tax assets	**4,032**	3,837
Deferred tax liabilities:		
Property related differences	**8,039**	7,416
Postretirement benefits - assets	**600**	479
Regulatory assets	**1,918**	1,883
Other items	**72**	57
Total deferred tax liabilities	**10,629**	9,835
Net deferred income tax liabilities	**6,597**	5,998
Deferred investment tax credits	**33**	37
Deferred income tax liabilities, net	**$ 6,630**	$ 6,035

Credit Carryforward

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

	Carryforward Amount *(in millions of dollars)*	Expiration Period
Investment Tax Credit	$ 21	2038 – 2044
Research and Development	65	2037 – 2046

Net Operating Losses

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

	Carryforward Amount *(in millions of dollars)*		Expiration Period
Federal	$ 1,575		Indefinite
Massachusetts	740		2044 – 2046
New York	2,215	(3)	2035 – 2046
New York City	190	(3)	2035 – 2046

(3) The amount contains net operating losses that were incurred before the tax year ended March 31, 2015 that have been converted into a Prior Net Operating Loss Conversion subtraction that can be utilized beginning fiscal year 2017.

As a result of the accounting for uncertain tax positions, the amount of deferred tax assets reflected in the consolidated 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:

Jurisdiction	Tax Years
Federal	March 31, 2023
Massachusetts	March 31, 2013
New York	March 31, 2016
New York City	March 31, 2016

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 statement of operations and comprehensive income. As of March 31, 2026 and 2025, the Company has accrued for interest related to unrecognized tax benefits of $24 million and $50 million, respectively. During the years ended March 31, 2026 and 2025, the Company recorded interest income of $15 million and interest expense of $20 million, respectively. No tax penalties were recognized during the years ended March 31, 2026 and 2025.

Income Tax Payments

	Year Ended March 31, 2026
	(in millions of dollars)
Federal	**$ (16)**
Massachusetts	**9**
New York	**(2)**
New York City	**(4)**
Other	**1**
Total cash (paid) refunded, net	**$ (12)**

13. ENVIRONMENTAL MATTERS

Ordinary business operations subject the Company to various federal, state, and local laws, rules, and regulations dealing with the environment, including air, water, and hazardous waste. The Company's business operations are regulated by various federal, regional, state, and local authorities.

Except as set forth below, no material proceedings relating to environmental matters have been commenced or, to the Company's knowledge, are contemplated by any federal, state, or local agency against the Company and the Company is not a defendant in any material litigation with respect to any matter relating to the protection of the environment. The Company believes that its operations are in substantial compliance with environmental laws and that requirements imposed by environmental laws are not likely to have a material adverse impact on the Company's financial position or results of operations.

Air

Genco's generating facilities are subject to increasingly stringent emissions limitations under current and anticipated future requirements of the EPA and the DEC. In addition to efforts to improve both ozone and particulate matter air quality, there has been an increased focus on greenhouse gas emissions in recent years. Genco's previous investments in low NOx boiler combustion modifications, the use of natural gas firing systems at its steam electric generating stations, and the compliance flexibility available under cap and trade programs have enabled Genco to achieve its prior emission reductions in a cost-effective manner. These investments include the installation of enhanced NOx controls and efficiency improvement projects at Genco's Long Island-based electric generating facilities including additional NOx reduction system installation at the Glenwood Unit 2, E.F. Barrett, and East Hampton gas turbine units. All of which have been placed in service as of the date of this report. The Company will continue to make investments for additional emissions reductions, as needed. Genco has developed a compliance strategy to address anticipated future requirements and is closely monitoring the regulatory developments to identify any necessary changes to its compliance strategy. At this time, Genco is unable to predict what effect, if any, these future requirements will have on its financial position, results of operations, and cash flows.

Water

Additional capital expenditures associated with the renewal of the surface water discharge permits for Genco's steam electric power plants have been required by the DEC pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts on aquatic organisms. Final permits have been issued, and capital improvements have been completed at Port Jefferson and Northport. Genco continues to engage in discussions with the DEC regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts at E.F. Barrett. Genco is awaiting a final permit from the DEC to proceed with the improvements at E.F. Barrett and will continue to operate under the prior permit, which is automatically extended under the State Administrative Procedure Act ("SAPA"). Costs associated with any necessary capital improvements or other mitigation measures are reimbursable from LIPA under the A&R PSA.

Land, Manufactured Gas Plants and Related Facilities

Federal and state environmental regulators, as well as private parties, have alleged that several of the Company's subsidiaries are potentially responsible parties under Superfund laws for the remediation of numerous contaminated sites in New York and New England. The Company's greatest potential Superfund liabilities relate to MGP facilities formerly owned or operated by its subsidiaries or their predecessors. MGP byproducts include fuel oils, hydrocarbons, coal tar, purifier waste, and other waste products which may pose a risk to human health and the environment.

Several lawsuits have been filed which allege damages resulting from contamination associated with the historic operations of a former MGP located in Bay Shore, New York. The Company has been conducting remediation at this location pursuant to Administrative Order on Consent with the DEC. The Company intends to contest these proceedings vigorously.

At March 31, 2026 and 2025, the Company's total reserve for estimated MGP-related environmental matters is $3.1 billion for both years. These liabilities are expected to be settled over approximately 54 years, and these undiscounted amounts have been recorded as estimated liabilities on the consolidated balance sheets. Management believes that obligations imposed on the Company because of the environmental laws will not have a material adverse effect on its operations, financial position, or cash flows. Through various rate orders issued by the NYPSC and the DPU, costs related to MGP environmental cleanup activities are recovered in rates charged to gas distribution customers. Accordingly, the Company has reflected a net regulatory asset of $3.1 billion on the consolidated balance sheets as of both March 31, 2026 and 2025. The Company is pursuing claims against other potentially responsible parties to recover investigation and remediation costs it believes are the obligations of those parties. The Company cannot predict the likelihood of success of such claims.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in compliance with all applicable environmental laws, and that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position since, as noted above, environmental expenditures incurred by the Company are generally recoverable from customers.

The Company is pursuing environmental insurance recoveries in connection with several legal proceedings that are ongoing between the Company and insurance companies who have provided historic coverage over environmentally impacted sites. Following any favorable resolution of these claims, the Company is expected to return insurance recoveries to customers through the Company's regulatory mechanisms. However, legal proceedings in each case still have a number of stages to complete, any of which could modify the amount of any eventual claim. As such it is not currently practicable to provide a reliable estimate of the amount of likely eventual recoveries.

14. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company's electric subsidiaries have several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the subsidiaries are obligated to make payment. Additionally, the Company's gas distribution subsidiaries have entered into various contracts for gas delivery, storage, and supply services. Certain of these contracts require payment of annual demand charges, which are recoverable from customers. The Company's gas distribution subsidiaries are liable for these payments regardless of the level of service required from third-parties. In addition, the Company has various capital commitments related to the construction of property, plant, and equipment and intangible assets.

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

(in millions of dollars) **Years Ending March 31,**	**Energy Purchases**	**Capital Commitments**
2027	$ 2,020	$ 714
2028	1,799	240
2029	1,776	185
2030	1,576	59
2031	1,364	19
Thereafter	13,634	18
Total	**$ 22,169**	**$ 1,235**

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 Massachusetts Electric 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 Services Inc. ("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. Massachusetts Electric Company received termination payments totaling approximately $49 million, which were returned to customers via bills between March 1, 2024, and February 28, 2025.

Financial Guarantees

The Company has guaranteed the principal and interest payments on certain outstanding debt of its subsidiaries. Additionally, the Company has issued financial guarantees in the normal course of business, on behalf of its subsidiaries, to various third-party creditors. At March 31, 2026, the following amounts would have to be paid by the Company in the event of non-payment by the primary obligor at the time payment is due:

Guarantees for Subsidiaries		**Amount of Exposure**	**Expiration Dates**
		(in millions of dollars)	
Surety Bonds	(i)	$ 173	Revolving
Purchasing Card Program	(ii)	60	Continuing
Letters of Credit	(iii)	302	September 2026 – February 2028
Nantucket Tax-exempt Bonds	(iv)	51	March 2039 – August 2042
Environmental Remediation Trust	(v)	64	2037
		$ 650	

The following is a description of the Company’s outstanding subsidiary guarantees:

(i) The Company has agreed to indemnify the issuers of various surety bonds associated with various construction requirements or projects of its subsidiaries. In the event that the Company or its subsidiaries fail to perform their obligations under contracts, the injured party may demand that the surety make payments or provide services under the bond. The Company would then be obligated to reimburse the surety for any expenses or cash outlays it incurs.

(ii) The Company’s US corporate card services program was pursuant to a Commercial Card Agreement between the banks and National Grid USA Service Company Inc. (“Service Company”), under which the banks established a corporate card program credit limit for the Company. The NGUSA Board of Directors previously authorized the Company to execute guaranty agreements in favor of the banks for the purpose of guaranteeing Service Company obligations under any commercial card or purchasing card agreements between Service Company and the banks.

(iii) The Company has arranged for stand-by letters of credit to be issued to third-parties that have extended credit to certain subsidiaries. Certain vendors require the posting of letters of credit to guarantee subsidiary performance under the Company’s contracts and to ensure payment to the Company’s subsidiary subcontractors and vendors under those contracts. Certain of the Company’s vendors also require letters of credit to ensure reimbursement for amounts they are disbursing on behalf of the Company’s subsidiaries, such as to beneficiaries under the Company’s self-funded insurance programs. Such letters of credit are generally issued by a bank or similar financial institution. The letters of credit commit the issuer to pay specified amounts to the holder of the letter of credit if the holder demonstrates that the Company has failed to perform specified actions. If this were to occur, the Company would be required to reimburse the issuer of the letter of credit.

(iv) The Massachusetts Electric 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 Massachusetts Electric 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 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 Massachusetts Electric 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.

(v) Brooklyn Union Gas Company is a guarantor of a lease agreement as part of its participation in a grantor trust established to manage and administer funds contributed towards cleanup efforts for environmental remediation. The trust maintains all obligations for the payment of rent, insurance and property taxes for the leased property. In the unlikely event that the trust was to default on required payments or be dissolved, Brooklyn Union would become responsible for those lease obligations. Total lease obligations (undiscounted) over the remaining 11 years are approximately $64 million.

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.

Northeast Supply Enhancement

On August 4, 2025, each of the Downstate New York Gas Companies executed separate precedent agreements with Transcontinental Gas Pipe Line Company, LLC (“Transco”) for the provision of firm natural gas transportation service in connection with Transco’s proposed Northeast Supply Enhancement (“NESE”) project. The NESE project is designed to add approximately 400,000 dekatherms per day of incremental firm capacity to Transco’s Rockaway Delivery Lateral, which interconnects with the Brooklyn Union Gas Company’s distribution system at Floyd Bennett Field in Brooklyn, New York. Pursuant to the precedent agreements, the Brooklyn Union Gas Company and KeySpan Gas East Corporation, have each committed to 188,700 Dth and 211,300 Dth of the new capacity, respectively, for an initial primary term of 15 years, commencing on the in-service date of the NESE project. The parties' obligations remain expressly conditioned upon the satisfaction of customary conditions precedent, including the receipt of all requisite federal, state, and local authorizations, permits, and approvals—among them a certificate of public convenience and necessity from FERC and all environmental approvals issued by the DEC—necessary to construct, own, and operate the NESE project.

FERC issued a certificate of public convenience and necessity for the project on August 28, 2025. On November 7, 2025, the DEC and the New Jersey Department of Environmental Protection granted water quality certifications. The FERC Certificate and state water quality certifications are subject to pending legal challenges. On March 3, 2026, FERC issued a "Notice to Proceed" for limited construction activity.

Nuclear Contingencies

As of March 31, 2026 and 2025, Niagara Mohawk had a liability of $211 million and $202 million, recorded in non-current liabilities on the consolidated balance sheets, for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Policy Act of 1982 and the Department of Energy's ("DOE") Standard Contract provide payment options for liquidating this one-time fee obligation. Niagara Mohawk has elected to defer payment, with interest, until the year in which Constellation Energy Corporation, initially plans to ship irradiated fuel to an approved DOE disposal facility.

In 2010, the federal budget eliminated essentially all funding for the development of the Yucca Mountain repository. A Blue-Ribbon Commission ("BRC") on America's Nuclear Future, appointed by the U.S. Secretary of Energy, issued its final report on January 26, 2012, with comprehensive recommendations for establishing a safe, long-term system to manage and dispose of the nation's spent nuclear fuel and high-level radioactive waste.

In January 2013, the DOE released its *"Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste"* in response to the BRC recommendations. This strategy contemplated a pilot consolidated interim storage facility on an aspirational timeline that is no longer operative. DOE has not begun accepting commercial spent nuclear fuel. Instead, DOE is pursuing a consent-based siting process for potential consolidated interim storage.

In the Consolidated Appropriations Act 2021, Congress appropriated funds to the DOE for interim storage-related activities. Interim storage remains an important component of a federal waste-management system because it would enable near-term consolidation and temporary storage of spent nuclear fuel, support research and operational learning, and build trust through a consent-based approach to siting.

DOE anticipates that any interim storage facility would operate until fuel can be transferred to a final disposal facility. The duration of the interim period will depend on completion of significant steps, including identifying a willing host community through the consent-based process, and then licensing, constructing, and placing into operation the relevant facilities, as well as the time required to transport spent nuclear fuel from reactor sites. Accordingly, Niagara Mohawk cannot predict the date on which DOE will begin accepting commercial spent nuclear fuel.

Amended and Restated Power Supply Agreements

Effective May 28, 2013 (and most recently amended on January 1, 2025), Genco provides services to LIPA under an amended and restated ("A&R") PSA. Under the A&R PSA, Genco has a return on equity on its monthly capacity charge of 10.6% and a capital structure of 50% debt and 50% equity.

The A&R PSA has a term of fifteen years, provided LIPA has the option to terminate the agreement on two years advance notice. Genco accounts for the A&R PSA and PPAs as operating leases under ASC 842. In addition, LIPA has options to ramp down blocks of capacity on two years advance notice for steam generating units, and one year advance notice for other generating units covered by the A&R PSA. Should any ramp downs be exercised, Genco is entitled to a ramp down payment equal to the net book value of the retired unit as defined in the A&R PSA, plus operating and maintenance expenses for 18 months for steam generating units and 12 months for all generating units. The ramp down payment for a steam unit includes a discount factor. This discount factor ranges from 50% of the unit's net book value if retired with an effective date in 2022 up to 62.5% of the unit's net book value if retired with an effective date thereafter. As requested by LIPA, National Grid's West Babylon GT, Glenwood GT 1, and Shoreham GT 2 generating units remain operational beyond their planned retirement date of May 1st, 2025. These units are required through September 30, 2026, to support the LIPA system in the event of an energy capacity shortage.

Effective February 1, 2023, FERC approved the amendments to the A&R PSA to reflect the terms of the Letter Agreement and the Side Letter. The Letter Agreement provided for further ramp down options, clarification on how a ramp down is calculated in regard to the capacity charge, and notional tracking account of $68M to offset initial ramp down payments, and confirmed recovery of $5 million of previously incurred costs, among other provisions. The Letter Agreement does not change the terms of the A&R PSA, except as explicitly discussed in the letter.

The A&R PSA provides potential penalties to Genco if it does not maintain the output capability of the generating facilities, as measured by annual industry-standard tests of operating capability, plant availability, and efficiency. These penalties may total $4 million annually. Although the A&R PSA provides LIPA with all the capacity from the generating facilities, LIPA has no obligation to purchase energy from the generating facilities and can purchase energy on a least-cost basis from all available sources consistent with existing transmission interconnection limitations of the transmission and distribution system. Genco must, therefore, operate its generating facilities in a manner such that Genco can remain competitive with other producers of energy. To date, Genco has dispatched to LIPA, and LIPA has accepted the level of energy generated at the agreed to price per megawatt hour. Under the terms of the A&R PSA, LIPA is obligated to pay for capacity at rates that reflect recovery of an agreed level of the overall cost of maintaining and operating the generating facilities, including recovery of depreciation and return on its investment in plant.

15. LEASES

The Company has various operating leases, primarily related to a transmission line, buildings, land, real estate, and fleet vehicles used to support the electric and gas operations, with lease terms ranging between 1 and 70 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 consolidated balance sheets. As of March 31, 2026 and 2025, the Company does not have any finance leases.

Expenses related to operating leases were $175 million and $144 million for the years ended March 31, 2026 and 2025, respectively.

As of March 31, 2026, the Company does 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:

	Years ended March 31,	
	2026	2025
	(in millions of dollars)	
Cash paid for amounts included in lease liabilities		
Operating cash flows from operating leases	**$ 177**	$ 146
ROU assets obtained in exchange for operating lease liabilities	**$ 232**	$ 201
Weighted-average remaining lease term – operating leases	**8 years**	10 years
Weighted-average discount rate – operating leases	**4.46%**	4.21%

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

	Operating Leases
Year Ending March 31,	*(in millions of dollars)*
2027	**$ 180**
2028	**168**
2029	**151**
2030	**132**
2031	**109**
Thereafter	**461**
Total future minimum lease payments	**1,201**
Less: imputed interest	**216**
Total	**$ 985**
Reported as of March 31, 2026:	
Current lease liability	**$ 142**
Non-current lease liability	**843**
Total	**$ 985**

Genco recognizes operating revenues related to the A&R PSA, and PPAs whereby LIPA agrees to purchase capacity, energy, and ancillary services from Genco and its subsidiaries. The agreements are classified as operating leases. The revenues earned from the contracts amounted to $490 million and $486 million for the years ended March 31, 2026 and March 31, 2025, respectively. There are other lease arrangements where the Company is the lessor. Revenue under such leases was immaterial for the years ended March 31, 2026 and March 31, 2025.

16. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

The Company engages in various transactions with the Parent and its subsidiaries. Certain activities and costs, including accounting, auditing, risk management, tax, and treasury/finance, human resources, information technology, legal, purchase gas, and strategic planning, are shared between the Company and its affiliates.

The Company also records short-term receivables from, and payables to, certain of its 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:

	Accounts Receivable from Non-consolidated Affiliates		Accounts Payable to Non-consolidated Affiliates	
	March 31,		March 31,	
	2026	2025	**2026**	2025
	(in millions of dollars)			
National Grid plc	**$ 80**	$ 167	**$ 167**	$ 239
National Grid North America	**5**	1	**-**	-
NGV US LLC ("NGV") and National Grid Partners LLC ("NGP")	**56**	530	**144**	174
Total	**$ 141**	$ 698	**$ 311**	$ 413

Advances from Affiliates

In August 2009, the Company entered into an agreement with the Parent, whereby either party can collectively borrow up to $3.0 billion from time to time for working capital needs, including funding of the regulated money pool, if necessary. In October 2024, the Company entered into a variation agreement to increase the borrowing limit from $3.0 billion to $5.0 billion until September 30, 2025. After the variation agreement ended, the borrowing limit reverted back to $3.0 billion. These advances currently bear interest rates of the Secured Overnight Financing Rate plus a margin set to reflect the cost of short-term borrowing rates for the Parent at the time of the borrowing. Outstanding balances are due on demand and reported on a net basis in the consolidated statements of cash flows. At March 31, 2026 and 2025, the Company had $1.8 billion and zero advances under this agreement, respectively.

In August 2008, the Company entered into an agreement with NGNA, whereby the Company can borrow up to $1.5 billion from time to time for working capital needs. The agreement can be amended and restated from time to time, with the latest amendment made in March 2025 to increase the borrowing capacity to $16.0 billion. These advances do not bear interest. At March 31, 2026 and 2025, the Company had $9.8 billion and $12.2 billion in outstanding advances from NGNA under this agreement, respectively.

Amounts advanced under each of these agreements are repayable on demand and can be structured as interest or non-interest bearing subject to the demands of the lender. The advances support general working capital needs, with advances and repayments executed on a daily basis.

Promissory Notes

On November 20, 2015, Genco entered into an intercompany loan with NGNA totaling $227 million, composed of a $165 million intercompany loan with an interest rate of 3.25% due to mature on April 30, 2028, and a $62 million intercompany loan with an interest rate of 3.13% due to mature on June 1, 2027. The remaining intercompany loan of $48 million and $66 million as of March 31, 2026 and 2025, respectively, is reported in long-term debt on the consolidated balance sheets. The intercompany loans also have an annual sinking fund requirement totaling $18 million, which is included in current portion of long-term debt on the accompanying consolidated balance sheets as of March 31, 2026 and 2025, respectively.

Intercompany money pool

The settlement of the Company's various transactions with its subsidiaries and certain affiliates generally occurs via the Regulated and Unregulated money pools, as applicable. Borrowings from the Regulated and Unregulated money pools bear interest in accordance with the terms of the applicable money pool agreement. All changes in the intercompany money pool balances are reflected as investing or financing activities in the accompanying consolidated statements of cash flows. For the purpose of presentation in the consolidated 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 and Unregulated money pools are funded by operating funds from participants in the applicable pool. The Intercompany money pool balances represent positions between the Company and legal entities that are part of the NGV and NGP business, which remains party to the Unregulated money pool. The cash impacts from these money pool positions were reported as either investing or financing activities in the consolidated statements of cash flows.

The average interest rates for the intercompany money pool were 4.5% and 5.1% for the years ended March 31, 2026 and 2025, respectively.

Holding Company Charges

The Company receives charges from National Grid Commercial Holdings Limited (an affiliated company in the United Kingdom) for certain corporate and administrative services provided by the corporate functions of the Parent to its U.S. subsidiaries. For the years ended March 31, 2026 and 2025, the effect on income before income taxes was $142 million and $106 million, respectively.

17. PREFERRED STOCK

Preferred stock of NGUSA subsidiaries

The Company's subsidiaries have certain issues of non-participating cumulative preferred stock outstanding where the security is guaranteed by National Grid plc and can be redeemed only at the option of the Company's subsidiaries. There are no mandatory redemption provisions on the cumulative preferred stock and no conversion options. A summary of the cumulative preferred stock of NGUSA subsidiaries at March 31, 2026 and 2025 is presented in the table below. The preferred stock is reported as a non-controlling interest as of March 31, 2026 and 2025, respectively.

		Shares Outstanding		**Amount**		
		March 31,		**March 31,**		Call
Series	Company	**2026**	2025	**2026**	2025	Price
		(in millions of dollars, except per share and number of shares data)				
$100 par value -						
3.40% Series	Niagara Mohawk	**57,524**	57,524	**$ 6**	$ 6	$ 103.500
3.60% Series	Niagara Mohawk	**137,152**	137,152	**14**	14	104.850
3.90% Series	Niagara Mohawk	**95,171**	95,171	**9**	9	106.000
4.44% Series	Massachusetts Electric	**22,585**	22,585	**2**	2	104.068
6.00% Series	NEP	**11,117**	11,117	**1**	1	Non-callable
Golden Shares	Niagara Mohawk and the New York Gas Companies	**3**	3	**-**	-	Non-callable
Total		**323,552**	323,552	**$ 32**	$ 32	

In connection with the acquisition of KeySpan by NGUSA, the Company's New York Gas Companies became subject to a requirement to issue a class of preferred stock, having one share (the "Golden Share"), subordinate to any existing preferred stock. The holder of the Golden Share would have voting rights that limit the Company's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceeding without the consent of the holder of the Golden Share. The NYPSC subsequently authorized the issuance of the Golden Share to a trustee, GSS Holdings, Inc. ("GSS"), who will hold the Golden Share subject to a Services and Indemnity Agreement requiring GSS to vote the Golden Share in the best interests of NYS. On July 8, 2011, the Company issued a total of 3 Golden Shares pertaining to Niagara Mohawk and the New York Gas Companies each with a par value of $1.

The Company's subsidiaries did not redeem any preferred stock during the years ended March 31, 2026 or 2025. The annual dividend requirement for cumulative preferred stock was $1 million as of March 31, 2026 and 2025.

Preferred stock of NGUSA

The Company has cumulative series A through F non-participating non-callable preferred stock (5,000 total shares authorized, 915 outstanding) which have no fixed redemption date and no conversion options. The series A through F shares rank above all common shares, but below the Company's debt holders in an event of liquidation. If the Company does not pay its annual dividend on the A through F series preferred stock due on July 28, it is subject to limitations on the payment of any dividends to its common shareholder. The par value of the series A through F preferred stock is $0.10. The fixed rate on the series A through E preferred stock is 6.5%. The fixed rate on the series F preferred stock is 8.5%. The Company has paid all declared dividends in full.

As of June 5, 2026, the NGUSA and NGNA Board of Directors have approved for the Company to enter into a Preferred Stock Repurchase Agreement to repurchase all the outstanding preferred shares owned by NGNA for $7.93 billion.

A summary of preferred stock is as follows:

	Shares Outstanding		**Amount (par)**		**Amount (additional paid-in capital)**		**Dividends Paid**	
	March 31,		**March 31,**		**March 31,**		**March 31,**	
Series	**2026**	2025	**2026**	2025	**2026**	2025	**2026**	2025
	(in millions of dollars, except per share and number of shares data)							
$0.10 par value -								
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400	**$ 26**	$ 26
Series B	**40**	40	**-**	-	**315**	315	**20**	20
Series C	**96**	96	**-**	-	**750**	750	**49**	49
Series D	**79**	79	**-**	-	**616**	616	**40**	40
Series E	**1**	1	**-**	-	**10**	10	**1**	1
Series F	**648**	648	**-**	-	**5,368**	5,368	**456**	456
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459	**$ 592**	$ 592