nationalgrid

National Grid North America Inc. and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2024 and 2023

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIESs

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

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
National Grid North America Inc.

Opinion

We have audited the consolidated financial statements of National Grid North America Inc. and Subsidiaries (the "Company"), which comprise the consolidated balance sheets as of March 31, 2024 and 2023, 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, 2024 and 2023, 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.

Emphasis of Matter

As discussed in Note 1 and Note 20 to the financial statements, the Company signed an agreement to sell its 100% indirect ownership in The Narragansett Electric Company which closed on May 25, 2022. Our opinion is not modified with respect to this matter.

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

July 10, 2024

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(in millions of dollars)

	Years Ended March 31,	
	2024	2023
Operating revenues	**$ 13,225**	$ 14,410
Operating expenses:		
Purchased electricity	**1,676**	2,102
Purchased gas	**1,566**	2,891
Operations and maintenance	**5,072**	4,759
Depreciation and amortization	**1,630**	1,506
Other taxes	**1,255**	1,335
Total operating expenses	**11,199**	12,593
Operating income	**2,026**	1,817
Other income (deductions):		
Interest on long-term debt, net	**(859)**	(704)
Other interest, including affiliate interest, net	**(141)**	(71)
Income (loss) from equity method investments	**23**	(28)
Other income, net	**379**	353
Gain on disposal of Millennium	**-**	339
Gain on disposal of Narragansett	**-**	847
Total other income (deductions)	**(598)**	736
Income before income taxes	**1,428**	2,553
Income tax expense	**231**	693
Net income	**1,197**	1,860
Net income attributed to non-controlling interests	**(2)**	(1)
Dividends on preferred stock	**(1)**	(1)
Net income attributed to common shareholders	**$ 1,194**	$ 1,858
Other comprehensive income, net of taxes:		
Unrealized gains (losses) on securities, net of tax expense (benefit) of \$1 and (\$2) in 2024 and 2023, respectively	**3**	(4)
Change in pension and other postretirement obligations, net of tax expense of \$5 and \$8 in 2024 and 2023, respectively	**15**	21
Unrealized gains (losses) on hedges, net of tax expense (benefit) of \$12 and (\$6) in 2024 and 2023, respectively	**33**	(15)
Total other comprehensive income	**51**	2
Comprehensive income	**$ 1,248**	$ 1,862
Less: Comprehensive income attributed to non-controlling interest	**(2)**	(2)
Comprehensive income attributed to common shareholders	**$ 1,246**	$ 1,860

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Years Ended March 31,	
	2024	2023
Operating activities:		
Net income	**$ 1,197**	$ 1,860
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**1,630**	1,506
Deferred income tax expense and amortization of investment tax credits	**241**	438
Bad debt expense	**247**	74
Gain on disposal of Narragansett	**-**	(847)
Gain on disposal of Millennium	**-**	(339)
Allowance for equity funds used during construction	**(82)**	(102)
Pension and postretirement benefit expense, net	**(40)**	41
Other, net	**15**	66
Dividends from equity method investments and other financial investments	**53**	71
Pension and postretirement benefits contributions	**(26)**	(70)
Environmental remediation payments	**(118)**	(112)
Changes in operating assets and liabilities:		
Accounts receivable and unbilled revenues, net	**(284)**	(390)
Inventory	**47**	(389)
Regulatory assets and liabilities (current), net	**(52)**	(376)
Regulatory assets and liabilities (non-current), net	**(1,255)**	(558)
Derivative instruments, net	**(57)**	484
Environmental remediation costs	**898**	235
Accounts payable and other liabilities	**(235)**	673
Transmission congestion contracts	**(150)**	114
Other assets and liabilities, net	**(91)**	(82)
Net cash provided by operating activities	**1,938**	2,297
Investing activities:		
Capital expenditures	**(4,991)**	(4,529)
Cost of removal	**(218)**	(192)
Proceeds from sale of assets	**73**	21
Proceeds from disposal of Narragansett	**-**	3,877
Proceeds from disposal of Millennium	**-**	552
Contributions to equity method investments	**(419)**	(539)
Purchases of financial investments	**(84)**	(87)
Proceeds from sales of financial investments	**86**	81
Other, net	**6**	1
Net cash used in investing activities	**(5,547)**	(815)
Financing activities:		
Common stock dividends to Parent	**-**	(2,130)
Payments on long-term debt	**(1,083)**	(1,460)
Proceeds from long-term debt	**3,728**	2,496
Commercial paper issued	**3,741**	5,918
Commercial paper paid	**(2,610)**	(5,912)
Other	**(71)**	(35)
Net cash provided by financing activities	**3,705**	(1,123)
Net increase in cash, cash equivalents, restricted cash and special deposits	**96**	359
Cash, cash equivalents, restricted cash and special deposits, beginning of year	**1,665**	1,306
Cash, cash equivalents, restricted cash and special deposits, end of year	**$ 1,761**	$ 1,665
Supplemental disclosures:		
Interest paid, net of amounts capitalized	**$ (792)**	$ (627)
Income taxes refunded (paid)	**(9)**	70
Significant non-cash items:		
Capital-related accruals included in accounts payable	**378**	298
ROU assets obtained in exchange for operating lease liabilities	**194**	309

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31, 2024	March 31, 2023
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 1,538**	$ 1,348
Restricted cash and special deposits	**223**	317
Accounts receivable, net	**2,374**	2,379
Unbilled revenues, net	**669**	559
Inventory	**920**	967
Regulatory assets	**747**	632
Prepaid taxes	**225**	269
Other current assets, net	**381**	327
Total current assets	**7,077**	6,798
Equity method investments	**1,473**	1,135
Property, plant and equipment, net	**47,341**	43,394
Non-current assets:		
Regulatory assets	**6,603**	5,265
Goodwill	**6,457**	6,457
Postretirement benefits	**1,438**	1,263
Financial investments	**722**	695
Other non-current assets, net	**357**	220
Total non-current assets	**15,577**	13,900
Total assets	**$ 71,468**	$ 65,227

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31,	
	2024	2023
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	**$ 2,063**	$ 2,331
Accounts payable to affiliates	**104**	81
Commercial paper	**1,823**	657
Current portion of long-term debt	**1,604**	871
Taxes accrued	**111**	82
Customer deposits	**81**	97
Interest accrued	**229**	184
Regulatory liabilities	**1,020**	969
Derivative instruments	**159**	253
Renewable energy certificate obligations	**220**	266
Payroll and benefits accruals	**444**	414
Environmental remediation costs	**255**	168
Other current liabilities	**825**	898
Total current liabilities	**8,938**	7,271
Non-current liabilities:		
Regulatory liabilities	**6,934**	6,568
Asset retirement obligations	**165**	149
Deferred income tax liabilities, net	**5,570**	5,168
Postretirement benefits	**586**	683
Environmental remediation costs	**3,002**	2,309
Derivative instruments	**225**	232
Operating lease liabilities	**741**	659
Other non-current liabilities	**833**	900
Total non-current liabilities	**18,056**	16,668
Commitments and contingencies (Note 16)		
Long-term debt	**20,839**	18,887
Equity:		
Common stock and additional paid-in capital	**14,214**	14,194
Retained earnings	**9,435**	8,274
Accumulated other comprehensive loss	**(78)**	(129)
Common shareholders’ equity	**23,571**	22,339
Non-controlling interests	**64**	62
Total equity	**23,635**	22,401
Total liabilities and equity	**$ 71,468**	$ 65,227

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

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NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(in millions of dollars)

	Common Stock [1]	Cumulative Preferred Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Unrealized Gain (Loss) on Securities	Pension and Other Postretirement Benefits	Hedging Activity	Foreign Currency translation	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests [2]	Total
Balance as of March 31, 2022	**$ -**	**$ -**	**$ 14,169**	**$ (7)**	**$ 30**	**$ (15)**	**$ (139)**	**$ (131)**	**$ 8,546**	**$ 68**	**$ 22,652**
Net income	-	-	-	-	-	-	-	-	1,859	1	1,860
Other comprehensive income (loss):											
Unrealized loss on securities, net of ($2) tax benefit	-	-	-	(4)	-	-	-	(4)	-	-	(4)
Change in pension and other postretirement obligations, net of $8 tax expense	-	-	-	-	21	-	-	21	-	-	21
Unrealized gains on hedges, net of ($6) tax benefit	-	-	-	-	-	(15)	-	(15)	-	-	(15)
Total comprehensive income											1,862
Stock-based compensation	-	-	25	-	-	-	-	-	-	-	25
Disposal of sub-preferred stock release	-	-	-	-	-	-	-	-	-	(3)	(3)
Common stock dividend to Parent	-	-	-	-	-	-	-	-	(2,130)	-	(2,130)
Preferred stock dividends	-	-	-	-	-	-	-	-	(1)	-	(1)
Other	-	-	-	-	-	-	-	-	-	(4)	(4)
Balance as of March 31, 2023	**$ -**	**$ -**	**$ 14,194**	**$ (11)**	**$ 51**	**$ (30)**	**$ (139)**	**$ (129)**	**$ 8,274**	**$ 62**	**$ 22,401**
Net income	-	-	-	-	-	-	-	-	1,195	2	1,197
Other comprehensive income (loss):											
Unrealized gains on securities, net of $1 tax expense	-	-	-	3	-	-	-	3	-	-	3
Change in pension and other postretirement obligations, net of $5 tax expense	-	-	-	-	15	-	-	15	-	-	15
Unrealized gains on hedges, net of $12 tax expense	-	-	-	-	-	33	-	33	-	-	33
Total comprehensive income											1,248
Stock-based compensation	-	-	20	-	-	-	-	-	-	-	20
Implementation of ASC 326, net of $12 tax benefit[3]	-	-	-	-	-	-	-	-	(33)	-	(33)
Common stock dividend to Parent	-	-	-	-	-	-	-	-	-	-	-
Preferred stock dividends	-	-	-	-	-	-	-	-	(1)	-	(1)
Other	-	-	-	-	-	-	-	-	-	-	-
Balance as of March 31, 2024	**$ -**	**$ -**	**$ 14,214**	**$ (8)**	**$ 66**	**$ 3**	**$ (139)**	**$ (78)**	**$ 9,435**	**$ 64**	**$ 23,635**

(1) The Company had 255 shares of common stock authorized, issued and outstanding, with a par value of $0.10 per share at March 31, 2024 and 2023.

(2) 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, 2024 and 2023, respectively. See Note 19, "*Preferred Stock*".

(3) See Note 5, "*Allowance for Doubtful Accounts*" for additional information.

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

National Grid North America Inc. ("NGNA" or "the Company") is a Delaware corporation that was created in the United States ("U.S.") as an indirect wholly-owned subsidiary of National Grid plc (the "Parent"), a public limited company incorporated under the laws of England and Wales. It is the intermediate holding company of National Grid USA ("NGUSA") and acts as a funding company on behalf of the Parent for certain subsidiaries' borrowings.

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 four 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, Maine, 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 Company's unregulated energy investments business consists of development investments such as natural gas pipelines, as well as certain other domestic energy-related investments.

NGV US LLC ("NGV") operates in competitive markets and includes the Company's investments in National Grid Renewables Development LLC ("NGRD"), formerly known as Geronimo Energy LLC., and Emerald Energy Venture LLC ("Emerald")). National Grid Partners LLC ("NGP") holds a portfolio of corporate venture capital investments in technology and innovation companies. On May 23, 2024, the Parent announced the streamlining of National Grid Ventures business and decision to sell National Grid Renewables. The held for sale criteria has not been met as of the issuance of these consolidated statements, and the assets continue to be classified as held and used.

The Company also has a wholly-owned subsidiary, National Grid LNG LLC, which is engaged in the business of receiving, storing, and redelivering liquefied natural gas ("LNG") in liquid and gaseous states, through facilities located in Providence, Rhode Island. On December 31, 2023, NGUSA transferred its ownership interest in National Grid LNG LLC, along with the ownership interest in National Grid LNG GP LLC and National Grid LNG LP LLC (collectively "NG LNG") to NGV. This transfer had no impact to the Company's financial position, results of operations, or cash flows.

On March 17, 2021, NGUSA announced the sale of its Rhode Island business (Narragansett) to PPL Energy Holdings, LLC. ("PPL") for $3.9 billion (excluding long-term debt). The sale closed on May 25, 2022, with all regulatory approvals obtained.

See Note 20, “*Sale of Narragansett*” for additional details. As of January 1, 2023, PPL operates the electric transmission facilities in Rhode Island on behalf of Narragansett.

The Company uses the equity method of accounting for its investments in affiliates when it has the ability to exercise significant influence over operating and financial policies but does not control the affiliates. The Company’s share of the earnings or losses of such affiliates is reported as part of Income from equity method investments in the accompanying consolidated statements of operations and comprehensive income (see Note 8, “*Equity Method Investments*” for additional details).

Under the current operating model, the Company has identified two reportable operating segments, representing the Company’s New York and New England operations. The Company’s unregulated operations are not material to report as a separate business segment. See Note 3, “*Segment Analysis*” for additional details.

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 July 10, 2024, 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, 2024, except as otherwise disclosed in this note and Note 7, “*Rate Matters*”.

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 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 4, "*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 17, "*Leases*" for additional details).

Income Taxes

Federal and state income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. 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 sufficient 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 consolidated 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. Excise taxes collected and expected to be paid for the years ended March 31, 2024 and 2023, were $136 million and $147 million, respectively.

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”) and 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. The Company had restricted cash of $127 million and $220 million and special deposits of $96 million and $97 million as of March 31, 2024 and 2023, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful account to reflect certain financial assets (including accounts receivable, unbilled accrued revenues, and other current assets and other non-current assets) net of expected credit losses, at estimated net realizable value. Effective April 1, 2023, the current expected credit loss model was applied for purposes of calculating the allowance for doubtful accounts.

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. The Company recorded bad debt expense of $262 million and $74 million for the years ended March 31, 2024 and 2023, respectively, within operations and maintenance expense in the accompanying consolidated statements of operations and comprehensive income. For the year ended March 31, 2023, bad debt expense reflects the impact of the Phase 1 and 2 Arrears Reduction programs. See Note 7, “*Rate Matters*” for additional details.

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, which represents net realizable value, and are expensed or capitalized into property, plant and equipment as used. There were no significant write-offs of obsolete inventory for the years ended March 31, 2024 or 2023.

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.

RECs are stated at cost and used to measure compliance with renewable energy standards. RECs support new renewable generation resources and are held primarily to be utilized in fulfillment of the Company’s compliance obligations. Emission credits are comprised of nitrogen oxide (“NOx”) and carbon dioxide credits. 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,	
	2024	2023
	(in millions of dollars)	
Materials and supplies	**$ 575**	$ 464
Gas in storage	**237**	343
Purchased RECs	**93**	99
Emission credits	**15**	61
Total inventory	**$ 920**	$ 967

Renewable Energy Standard Obligations

RECs and Zero-Emissions Credits ("ZECs") are stated at cost and used to measure compliance with renewable energy standards. RECs support new renewable generation resources whereas ZECs support generation by in-state nuclear power plants and are purchased from third parties. RECs and ZECs are held primarily to be utilized in fulfillment of the Company's compliance obligations. As of March 31, 2024 and 2023, the Company recorded renewable energy certificate obligations of $220 million and $266 million, respectively.

Transmission congestion contracts

The Company participates in the New York Independent Service 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 4, "*Revenue*" for additional details.

Derivative Instruments

The Company uses derivative instruments to manage commodity price, interest rate, and foreign currency rate risk (see Note 10, "*Derivative Instruments and Hedging*"). 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 11, "*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.

Qualifying derivative instruments are designated as fair value or cash flow hedges. Changes in the fair value of the derivative designated in a cash flow hedge are initially recognized in accumulated other comprehensive income ("AOCI"), net of related tax effects. In a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item in relation to the risk being hedged are both adjusted on the balance sheet and offset in the statements of operations and comprehensive income, with the residual difference remaining as ineffectiveness. For both types of hedges, qualifying derivative gains and losses related to the value of currency basis are treated separately as "costs of hedging" and are deferred in a separate component of AOCI. The Company has elected to classify the cash flows from derivatives designated in a qualifying fair value or cash flow hedging relationship in the same category as the cash flows from the hedged items within the consolidated statements of cash flows.

Amounts accumulated in AOCI are reclassified to the statements of operations and comprehensive income on a systematic basis as the hedged income or expense is recognized. Adjustments made to the carrying value of hedged items in fair value hedges are similarly released to the consolidated statements of operations and comprehensive income to match the timing of the hedged income or expense. When hedge accounting is discontinued, any remaining cumulative hedge accounting balances continue to be released to the statement of operations and comprehensive income to match the impact of outstanding hedged items. If a forecast transaction becomes no longer probable, the cumulative gain or loss previously reported in equity would be transferred to the statement of operations and comprehensive income. This has not occurred during the years ended March 31, 2024 or 2023.

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, 2024 or 2023.

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.

Variable Interest Entities

Variable interest entities ("VIEs") are entities that lack either of the following characteristics: (1) the total equity investment at risk is sufficient to enable the entity to finance its ongoing activities, or (2) the equity investors have power to direct the most significant activities of the entity (the activities that impact the economic performance of the entity), the obligation to absorb expected losses of the entity, and the right to receive the residual returns of the entity. The primary beneficiary is the enterprise that has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or right to receive benefits that could be significant to the VIE. The primary beneficiary holds a controlling financial interest in the entity and is required to consolidate the VIE.

The Company determines whether it is the primary beneficiary of a VIE by evaluating the purpose and design of the entity, the nature of the VIE and the variability the entity is designed to create and pass along to its interest holders, who has the power to direct the activities of the VIE that most significantly impact the economic performance of the VIE, and who has the obligation to absorb losses or receive benefits that could be significant to the VIE.

See Note 8, "*Equity Method Investments*" for additional details.

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 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.

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, including certain equity method investments, 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.

Hypothetical Liquidation at Book Value

The Company accounts for its share of the earnings of the projects owned by Emerald using the equity method of accounting under the hypothetical liquidation at book value ("HLBV") method. Under this method, the Company calculates the amount each owner would receive if the partnership were liquidated at book value at the end of each measurement period based on the contractual liquidation provisions in the applicable partnership agreements. The change in amount allocated to each partner after adjusting for distributions and contributions is recorded as income or loss for that period in the consolidated statements of operations and comprehensive income.

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, 2024 and 2023 are as follows:

	Composite Rates	
	Years Ended March 31,	
	2024	2023
Electric	**2.8%**	2.8%
Gas	**2.4%**	2.4%
Common	**12.8%**	12.7%

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 asset or regulatory liability. 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 6," *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 $82 million and $102 million and AFUDC related to debt of $62 million and $50 million for the years ended March 31, 2024 and 2023, respectively. The average AFUDC rates for the years ended March 31, 2024 and 2023 were 7.0% and 6.6%, 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.

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, 2024, the Company tested goodwill residing at NGNA based upon three identified reporting units, New York, New England, and NGV Renewables.

At March 31, 2024 and 2023, the carrying value of goodwill primarily includes amounts assigned to the New England and New York reporting units, representing the Company's reportable segments (see Note 3, "*Segment Analysis*" for additional details). As of March 31, 2024, the carrying value of goodwill assigned to the New England and New York reporting units amounted to approximately $2,309 million and $3,981 million, respectively. As of March 31, 2023, the carrying value of goodwill assigned to the New England and New York reporting units amounted to $2,364 million and $3,981 million, respectively. There are no historical accumulated impairment losses included in the carrying values of goodwill.

Effective December 31, 2023, NG LNG was legally transferred out of the NGUSA consolidated group and became a direct subsidiary of the NGNA group. As a result of this realignment, goodwill of $55 million was reallocated from the New England reporting unit to the NGV Renewables reporting unit using a relative fair value approach. This transfer did not result in changes to the total goodwill carrying amount at the consolidated NGNA level.

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.

During the year ended March 31, 2023, the Company changed the date of the annual impairment test from January 1 to October 1. Management has determined that the use of October 1 as its annual goodwill impairment test date is preferable compared to January 1 given it aligns better with the long-range planning and forecasting process, and it also facilitates a timelier evaluation in advance of the Company's reporting period. The movement of the date has not resulted in any change in the timing of recording any potential impairment, nor does it represent a material change to a method of applying accounting principle, and thus, prospective treatment is appropriate.

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, principally discounted projected future net cash flows and market-based multiples, commonly referred to as the income approach and market approach. Key assumptions include, but are not limited to, estimated future cash flows, multiples of earnings, and an appropriate discount rate. 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, 2024, 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.

For goodwill at the NGV Renewables reporting unit, the Company estimates the fair value based solely on the income approach. The Company believes that this approach provides the most reliable information about estimated fair value based on the reporting unit's renewable development activities and overall operations.

The Company performed its latest annual goodwill impairment test as of October 1, 2023, 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, 2024 or 2023.

Financial Investments

The Company holds a range of financial investments, including life insurance policies, equity securities 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.

Equity securities consist of shares held as part of a portfolio of financial instruments, such as corporate stocks and mutual funds, and are measured at fair value with changes in fair value recorded in earnings.

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.

Other financial investments are primarily comprised of corporate venture capital investments held by NGP and investments held by NGV. 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,	
	2024	2023
	(in millions of dollars)	
COLI/TOLI	**$ 296**	$ 286
Debt securities [1]	**203**	217
Equity securities [1]	**137**	120
SERPs [1]	**30**	25
Other [1]	**56**	47
Total financial investments	**$ 722**	$ 695

[1] See Note 11, "*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 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 these subsidiaries are rate-regulated, these companies apply regulatory accounting guidance and 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 other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices.

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 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 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.

Reference Rate

The benchmark interest rates hedged are currently based on Secured Overnight Financing Rate ("SOFR"). US London Interbank Offered Rate ("LIBOR") was replaced as an interest rate benchmark by alternative reference rates ("ARRs") in certain currencies including USD, and foreign currencies in which the Company operates. This impacted contracts including financial liabilities that pay LIBOR-based cash flows, and derivatives that receive or pay LIBOR-based cash flows. The Company has managed the risk by replacing US LIBOR cash flows with SOFR on its affected contracts. The Company has amended all of its current agreements that have LIBOR as a reference rate during the years ended March 31, 2024.

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, 2024 and 2023.

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

Reference Rate

In January 2021, the FASB issued ASU No. 2021-01 *"Reference Rate Reform (Topic 848): Scope"* clarifying the application of the optional relief and practical expedients for certain transactions, including contract modifications and hedging relationships affected by reference rate reform, as well as those that do not directly reference London Interbank Offered Rate (LIBOR), or any other reference rate expected to be discontinued. The standard applies to all entities that elect to apply the optional guidance in Topic 848 and is effective immediately. The Company adopted ASU 2021-01 in January 2021 with no impact upon adoption. In December 2022, the FASB issued ASU No. 2022-06 "*Reference Rate Reform (Topic 848): Deferral of Sunset Date of Topic 848"* to extend the reference rate reform transition period to December 31, 2024, all applicable agreements that previously used LIBOR as a reference rate have been amended to SOFR. The adoption did not materially affect the Company's financial position, results of operations, or cash flows.

Financial Instruments – Credit Losses

In June 2016, the FASB issued ASU No. 2016-13 "*Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Statements*" which requires a financial asset (or a group of financial assets) measured at amortized cost basis to be presented at the net amount expected to be collected. The accounting standard provides a new model for recognizing credit losses on financial instruments based on an estimate of current expected credit losses that replaces existing incurred loss impairment methodology requiring delayed recognition of credit losses. A broader range of reasonable and supportable information must be considered in developing estimates of credit losses. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. Credit losses relating to available-for-sale debt securities should be recorded through an allowance for credit losses.

In May 2019, the FASB issued ASU 2019-05, "*Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief*", permitting entities to irrevocably elect the fair value option for financial instruments that were previously recorded at amortized cost basis within the scope of Topic 326, except for held-to-maturity debt securities. In March 2022, the FASB issued ASU 2022-02, "*Financial Instruments—Credit Losses (Topic 326): Troubled Debt Restructurings and Vintage Disclosures.*" The update eliminates the accounting guidance for troubled debt restructurings by creditors and enhances the disclosure requirements for loan refinancing and restructurings made with borrowers experiencing financial difficulty. In addition, the amendments require a public business entity to disclose current period gross write-offs for financing receivables and net investment in leases by year of origination in the vintage disclosures.

The Company adopted this new guidance on April 1, 2023. See Note 5, "*Allowance for Doubtful Accounts*" for further information.

Accounting Guidance Not Yet Adopted

Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions

In June 2022, the FASB issued ASU 2022-03, *"Fair Value Measurement (Topic 820): Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions,"* which clarifies that a contractual sale restriction of an equity security is not considered part of the unit of account of the equity security and, therefore, is not considered in measuring fair value. The update also provides specific disclosure requirements related to such equity security. The Company will adopt the requirements of the new standard prospectively on April 1, 2024. The Company is currently assessing the application of the new guidance but does not expect the adoption to have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Leases (Topic 842): Common Control Arrangements

In March 2023, the FASB issued ASU 2023-01, "*Leases (Topic 842): Common Control Arrangements*" which requires leasehold improvements in common control leases be amortized by the lessee over the useful life of the improvements with no consideration of the lease term as long as the lessee controls the use of the underlying asset. Further, a lessee that no longer controls the use of the underlying asset will account for the transfer of the underlying asset as an adjustment to equity.

The Company will adopt this standard for annual periods effective April 1, 2024, including interim periods. The Company is currently assessing the application of the new guidance but does not expect the adoption to have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Segment Reporting (Topic 280): Reportable Segment Disclosures

In November 2023, the FASB issued ASU 2023-07, "*Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*" which improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses.

The Company will adopt this standard for annual periods effective April 1, 2024. The Company is currently assessing the application of the new guidance but does not expect the adoption to have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Income Taxes (Topic 740): Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, "*Income Taxes (Topic 740): Improvements to Income Tax Disclosures*" which improves the income tax disclosures by requiring disaggregated information about a reporting entity's effective tax rate reconciliation as well as information on income taxes paid.

The Company will adopt this standard for annual periods effective April 1, 2025. The Company is currently assessing the application of the new guidance but does not expect the adoption to have a material impact.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements to conform the prior period's balances to the current period's presentation. These reclassifications had no effect on reported income, statement of cash flows, total assets, or stockholders' equity as previously reported.

3. SEGMENT ANALYSIS

Revenue and the business results are analyzed by operating segment, based on information that the Parent's Board of Directors (the "Board") uses internally to evaluate each operating segment's performance to determine resource allocations between them. The Board serves as the Company's chief operating decision-maker ("CODM") and assesses the profitability of operations based principally on operating profit.

The following is a brief description of the primary activities undertaken by these reportable operating segments:

New York	Gas distribution networks, electricity distribution networks, and high-voltage electricity transmission networks, located throughout New York.
New England	Gas distribution networks, electricity distribution networks, and high-voltage electricity transmission networks located throughout New England.

The NGV operating segment, which now manages the operations of NG LNG under the Company's operating model, and continues to include the Company's investments in Genco and NGRD, does not meet the thresholds required by ASC 280, "*Segment Reporting*", to be identified as a separate reportable segment. The tables below reflect NG LNG activity in "NGV and Other" for the year ended March 31, 2024. The prior period amounts have been restated for the transfer of NG LNG from "New England" to "NGV Other". Further, NGP and the Company's other insurance and corporate activities do not form part of any of the operating segments under the new operating model and are reported to the Board on an aggregated basis. These non-reportable segments are aggregated and presented as "NGV and Other" in the segmental schedules below.

Revenue

	Year Ended March 31, 2024 ***(in millions of dollars)***			Year Ended March 31, 2023 *(in millions of dollars)*		
	Total Revenue	**Intercompany Revenue**	**External Customer Revenue**	Total Revenue	Intercompany Revenue	External Customer Revenue
Reportable operating segments:						
New York	**$ 7,487**	**$ -**	**$ 7,487**	$ 8,274	$ -	$ 8,274
New England	**5,314**	**(483)**	**4,831**	5,815	(446)	5,369
Total reportable segment revenue	**12,801**	**(483)**	**12,318**	14,089	(446)	13,643
Reconciliation to consolidated totals:						
Total reportable segment revenue	**12,801**	**(483)**	**12,318**	14,089	(446)	13,643
NGV and Other	**953**	**(46)**	**907**	775	(8)	767
Total consolidated revenue	**$ 13,754**	**$ (529)**	**$ 13,225**	$ 14,864	$ (454)	$ 14,410

The following schedules present revenues from contracts with customers and other revenues from sources other than contracts with customers for reportable segments and all other segments, disaggregated by major source:

	Year Ended March 31, 2024 ***(in millions of dollars)***			
	New York	**New England**	**NGV & Other**	**Consolidated Total**
Revenue from contracts with customers:				
Electric services	**$ 3,512**	**$ 2,849**	**$ -**	**$ 6,361**
Gas distribution	**3,953**	**1,940**	**13**	**5,906**
Off system sales	**111**	**89**	**-**	**200**
Other	**-**	**-**	**188**	**188**
Total revenue from contracts with customers	**7,576**	**4,878**	**201**	**12,655**
Other revenue sources:				
Revenue from alternative revenue programs	**(120)**	**(76)**	**-**	**(196)**
Other revenue	**31**	**29**	**706**	**766**
Total operating revenue	**$ 7,487**	**$ 4,831**	**$ 907**	**$ 13,225**

	Year Ended March 31, 2023 *(in millions of dollars)*			
	New York	New England	NGV & Other	Consolidated Total
Revenue from contracts with customers:				
Electric services	$ 3,535	$ 3,042	$ -	$ 6,577
Gas distribution	4,538	2,070	6	6,614
Off system sales	368	192	-	560
Other	-	-	149	149
Total revenue from contracts with customers	8,441	5,304	155	13,900
Other revenue sources:				
Revenue from alternative revenue programs	(197)	28	-	(169)
Other revenue	30	37	612	679
Total operating revenue	$ 8,274	$ 5,369	$ 767	$ 14,410

Operating Income and Reconciliation to Consolidated Income Before Income Taxes

The following schedule provides a reconciliation of operating income by reportable segment and to total consolidated operating income before income tax:

	Years Ended March 31, (in millions of dollars)	
	2024	2023
Reportable operating segments:		
New York	**$ 1,166**	$ 1,129
New England	**870**	666
Total operating income from reportable segments	**2,036**	1,795
Reconciliation to consolidated totals:		
Total operating income from reportable segments	**2,036**	1,795
NGV and Other	**(10)**	22
Total consolidated operating income	**2,026**	1,817
Reconciliation to income before income taxes:		
Total consolidated operating income	**2,026**	1,817
Interest on long-term debt, net	**(859)**	(704)
Other interest, including affiliate interest, net	**(141)**	(71)
Income (loss) from equity method investments	**23**	(28)
Other income, net	**379**	353
Gain on disposal of Millennium	**-**	339
Gain on disposal of Narragansett	**-**	847
Total consolidated income before income taxes	**$ 1,428**	$ 2,553

Capital Expenditures

Capital expenditures represents additions to property, plant, and equipment and other intangible assets but excludes additional investment in, and loans to, joint ventures and equity investments.

	Capital Expenditures		Depreciation and Amortization	
	March 31,		March 31,	
	2024	2023	**2024**	2023
	(in millions of dollars)		(in millions of dollars)	
Operating segments:				
New York	**$ 3,092**	$ 2,600	**$ 857**	$ 792
New England	**1,997**	1,762	**689**	652
Total from reportable segments	**5,089**	4,362	**1,546**	1,444
Reconciliation to consolidated totals:				
Total from reportable segments	**5,089**	4,362	**1,546**	1,444
NGV and Other	**52**	216	**84**	62
Consolidated total	**$ 5,141**	$ 4,578	**$ 1,630**	$ 1,506

4. REVENUE

The following table presents, for the years ended March 31, 2024 and 2023, 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	
	2024	2023
	(in millions of dollars)	
Revenue from contracts with customers:		
Electric services	**$6,361**	$ 6,577
Gas distribution	**5,906**	6,614
Off system sales	**200**	560
Other	**188**	149
Total revenue from contracts with customers	**12,655**	13,900
Revenue from alternative revenue programs	**(196)**	(169)
Other revenue	**766**	679
Total operating revenues	**$13,225**	$ 14,410

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 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.

Distribution 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, Rhode Island, New Hampshire, and Vermont. The Company's transmission services are regulated by the FERC, ISO NE, NYISO and the MA DPU. 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.

Other revenues from contracts with customers: Primarily relates to revenues at NGRD from the sale of renewable projects. NGRD recognizes revenue for projects sold when all performance obligations have been fulfilled and it is probable that a significant reversal in the amount of revenue recognized will not occur.

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 revenue decoupling mechanisms ("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. Niagara Mohawk's 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 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: Includes lease income and other transactions, including pole rentals, capital related operations and maintenance billings that are not considered contracts with customers. Lease income 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.

5. 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 had a total allowance for doubtful accounts of $687 million and $631 million, of which $634 million and $631 million relates to Accounts receivable, $34 million and zero relates to Unbilled revenues, $2 million and zero relates to Other current assets, and $17 million and zero relates to Other non-current assets, as of the years ended March 31, 2024 and 2023, respectively. The activity in the allowance for doubtful accounts for the year ended March 31, 2024 is as follows:

	Year Ended March 31, 2024 *(in millions of dollars)*		
	Utility Accounts Receivables	Non-Utility Accounts Receivables	**Total Allowance**
Beginning Balance	$ 582	$ 49	**$ 631**
Impact of adoption of ASC Topic 326 on April 1, 2023	24	23	**47**
Credit Loss Expense	239	4	**243**
Write-Offs	(291)	(9)	**(300)**
Recoveries	60	6	**66**
Ending Balance	$ 614	$ 73	**$ 687**

6. 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,	
	2024	2023
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 106**	$ 138
Gas cost adjustment mechanisms	**107**	95
Rate adjustment mechanisms	**164**	110
Renewable energy certificates	**74**	105
Revenue decoupling mechanisms	**149**	104
Other	**147**	80
Total	**747**	632
Non-current:		
Cost of removal	**76**	58
Environmental response costs	**3,423**	2,647
Net metering deferral	**340**	234
Postretirement benefits	**504**	564
Storm costs	**895**	694
Arrears reduction	**193**	235
Other	**1,172**	833
Total	**6,603**	5,265
Regulatory liabilities		
Current:		
Energy efficiency	**336**	337
Gas cost adjustment mechanisms	**96**	144
Rate adjustment mechanisms	**437**	316
Revenue decoupling mechanisms	**67**	90
Profit sharing	**47**	51
Other	**37**	31
Total	**1,020**	969
Non-current:		
Cost of removal	**1,899**	1,723
Environmental response costs	**250**	193
Postretirement benefits	**1,410**	1,232
Regulatory tax liability	**1,996**	2,150
Other	**1,379**	1,270
Total	**$ 6,934**	$ 6,568

Regulatory assets associated with future financial obligations that were deferred in accordance with orders issued by the NYPSC and DPU do not earn a return until such time a cash outlay has been made. As of March 31, 2024, regulatory assets of $3,926 million ($3,175 million for Environmental response costs, $549 million for Postretirement benefits, $122 million for Other costs and $80 million for Derivative instruments) did not earn a return. As of March 31, 2023, regulatory assets of $323 million ($199 million of Postretirement benefits, $66 million of Environmental response costs and $58 million of Other costs) did not earn a return. The recovery period of these regulatory assets is to be determined in future rate plans or other orders issued by the NYPSC and DPU.

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, 2024 and 2023 was $242 million and $187 million, respectively.

Arrears reduction: The arrears reduction program was implemented in compliance with the proceeding to address Energy Affordability for Low Income Utility Customers and the proceeding regarding the Effects of Covid-19 on Utility Service. The program addresses arrears held by low-income customers and is funded by a combination of state funds, shareholder contributions, existing energy affordability program liabilities as well as surcharge to other 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: The Company evaluates open commodity derivative instruments for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative instruments that qualify for recovery 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.

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.

Gas costs adjustments: 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 of supply. These amounts will be refunded to, or recovered from, customers over the next year.

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 mechanism to recover such amounts.

Postretirement benefits: The regulatory asset balance 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.

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

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.

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

Renewable energy certificates: Represents deferred costs associated with the Company’s compliance 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.

Revenue decoupling mechanisms (“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.

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 7, “*Rate Matters*”, for additional information regarding the recovery of storm costs.

7. RATE MATTERS

Niagara Mohawk

Electric and Gas Filing

On May 28, 2024, Niagara Mohawk filed to increase revenues by $525 million and $148 million, for its electric and gas businesses, respectively, in the twelve months ending March 31, 2026 (“Rate Year One”). While Niagara Mohawk’s rate filings propose new rates for Rate Year One only, cost data for three additional years have been included to facilitate a potential multi-year settlement. If approved, the new rate increases would take effect from May 1, 2025.

These rate filings demonstrate National Grid’s commitment to continuing its support of New York’s energy policies and meeting the challenges of climate change, while also ensuring the overall reliability, resiliency, and affordability of the energy systems and includes numerous investments and programs that will reduce emissions and advance the clean energy goals of the Climate Leadership and Community Protection Act (“CLCPA”). Specific proposals include (i) electric network upgrades to connect renewable generation and support electric vehicles and battery storage, (ii) programs to promote heat electrification and non-wires/pipes alternatives; (iii) initiatives to support affordability and benefit low-income customers and disadvantaged communities; (iv) targeted gas main replacements and leak repairs to enhance safety and reduce system emissions, and (v) expanded energy efficiency, weatherization, and demand response offerings.

General Rate Case

On September 27, 2021, Niagara Mohawk, the Department of Public Service (“DPS”) Staff and other settlement parties filed a Joint Proposal (“NIMO-JP”) for a three-year rate plan for Niagara Mohawk’s electric and gas businesses beginning July 1, 2021 and ending June 30, 2024. The highlights of the rate plan include: enhanced energy affordability programs (“EAP”) and services for low and moderate income customers; initiatives to reduce methane emissions and deploy clean energy solutions, including electric vehicles (“EV”), battery storage and energy efficiency and demand response programs, in support of the CLCPA; support for deploying Advanced Metering Infrastructure (“AMI”); and funding for $3.3 billion in capital projects to improve safety, resiliency and reliability of our energy networks. The proposed revenue increases are 1.4% for electric operations and 1.8% for gas operations in Rate Year 1 and 1.9% for both electric and gas operations in Rate Year 2 and Rate Year 3. In addition, the NIMO-JP also includes mechanisms that would allow Niagara Mohawk to extend the rate plan by nine months ("Stayout Period"). To mitigate the potential bill impacts on customers, the settlement applies existing deferral credits of $146 million and $54 million for electric and gas customers, respectively, over the term of the rate plan and Stayout Period. The settlement is based upon a 9% return on equity and a ratemaking capital structure reflecting a common equity component of 48%. The NIMO-JP includes an earnings sharing mechanism by which customers will share in earnings in excess of a 9.5% calculated return on equity for each rate year under the rate plan.

On January 20, 2022, the NYPSC approved and adopted the three-year settlement through June 30, 2024 and supporting schedules for Niagara Mohawk's electric and gas businesses with limited additional requirements. Pursuant to the NIMO-JP, Niagara Mohawk recorded the Make Whole provision with new rates effective February 1, 2022 to ensure Niagara Mohawk was restored to the same financial position it would have been in had new rates gone into effect July 1, 2021. The NYPSC stated in its approval that the agreed upon electric and gas rate plans will result in sufficient mitigation of rate impacts on customers while preserving Niagara Mohawk's operational and financial stability; are consistent with the environmental, social and economic policies of the Commission and the State of New York, including the CLCPA; and fall within the range of potential litigated outcomes or otherwise provide benefits to ratepayers that could not have been achieved in a fully litigated proceeding. Beginning July 1, 2024, Niagara Mohawk will begin the Stayout Period which will continue the provisions of the current rate plan with some modifications, including the deferral of incremental revenue requirement over the allowance in base rates for the net utility plant and depreciation expense reconciliation mechanism (capped at forecast levels) and Commission-approved energy efficiency costs not recovered in base rates to achieve energy efficiency targets (not to exceed the authorized budget) for the nine months ending March 31, 2025.

Advanced Metering Infrastructure

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. The upstate New York Smart Meter program will provide our customers with real-time energy consumption data and tools to make clean energy choices and reduce costs. The approval assumes a six-year project deployment schedule (two years of back-office systems followed by four years of electric meter and gas module deployment). Niagara Mohawk started scaled meter deployment in the third quarter of calendar year 2023 and anticipates the deployment of gas modules in the fourth quarter of calendar year 2024. Niagara Mohawk intends to install approximately 1.7 million electric AMI meters and 640,000 gas modules across its service territory. 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.

Energy Affordability Programs

COVID-19 Recovery

On January 20, 2021, the DPS Staff issued a guidance letter regarding deferral treatment of incremental COVID-19 costs. The letter articulated two scenarios under which utilities could seek deferral of such costs – through change in law provisions contained in utilities' existing rate plans or through a separate deferral petition. On December 16, 2021, Niagara Mohawk notified the NYPSC that under its previous and current rate plan provisions Niagara Mohawk has met the requirements during Rate Year 3 and the Stayout Period to defer, for ratemaking purposes, the unbilled fees (late payment charges and other waived fees, net of related savings) of approximately $17 million and $3 million, for the electric and gas businesses, respectively, resulting from New York State's COVID-related orders and legislation. On February 7, 2022, the New York Companies petitioned for approval of an alternative recovery mechanism for the COVID-19 related unbilled fees that are deferred during the term of the rate plans. On June 16, 2022, the NYPSC approved Niagara Mohawk's petition for an alternative recovery mechanism of COVID-19 unbilled fees, whereby, Niagara Mohawk will collect its deferral for the last fifteen months of its prior rate plan (April 1, 2020 – June 30, 2021) of $17 million for the electric business and $3 million for the gas business through a surcharge effective July 1, 2022, through June 30, 2023. In addition, the NYPSC authorizes Niagara

Mohawk to surcharge or credit the deferred COVID-19 unbilled fees, net of related savings, for Rate Years 1 and 2 under its current rate plan during the periods from July 1, 2023, through June 30, 2024, and July 1, 2024, through June 30, 2025, respectively. The order also approved Niagara Mohawk's proposal to commit $2 million of the deferred unbilled fee toward customer arrearages, discussed below. In June 2022, Niagara Mohawk met the requirements under U.S. GAAP to recognize the revenues for the COVID-19 unbilled fees for the amounts deferred through June 30, 2022. Accordingly, Niagara Mohawk recorded the revenue related to the COVID-19 unbilled fees deferral, in fiscal year 2023, of $28 million to revenue from ARPs and the associated interest income of $2 million on the deferral to other income, net.

Phase 1 Arrears Reduction Program

In May 2022, the Energy Affordability Policy working group ("EAP Working Group") issued an Arrears Report recommending, among other matters, to implement an arrears reduction program in two phases. The first phase ("Phase 1") would target low-income customers to provide much needed COVID-19 related relief through a one-time bill credit that eliminates accrued arrears through May 1, 2022, with portions above the $250 million state appropriation being funded from a combination of sources including ratepayers. The second phase ("Phase 2") would allow the EAP Working Group to develop a program designed to reduce arrears for customers who were not eligible for arrears relief under the Phase 1 program.

On June 16, 2022, the NYPSC approved the recommendations made in the Phase 1 Arrears Report discussed above. The order authorized the implementation of the Phase 1 Arrears Reduction Program, whereby, Niagara Mohawk's total EAP arrears reduction one-time bill credits are to be funded by approximately $40 million from the New York State budget allocation, a shareholder contribution of $2 million under Niagara Mohawk's approved petition for alternative recovery mechanism of COVID-19 unbilled fees, utilization of $25 million from existing deferred EAP liabilities, with the remaining balance to be recovered from customers through a surcharge over a three year recovery period effective on August 1, 2022. Niagara Mohawk issued a total of approximately $106 million of Phase 1 EAP one-time bill credits to its electric and gas customers for the program.

Phase 2 Arrears Reduction Program

On December 23, 2022, the EAP Working Group filed the Phase 2 Arrears Report recommending that the NYPSC adopt a second phase of relief for COVID-19 related arrears through May 1, 2022 for residential non-EAP customers who did not receive relief under Phase 1 and for small commercial customers' arrears.

On January 19, 2023, the NYPSC approved the EAP Working Group's Phase 2 proposal ("Phase 2 Order"). The Phase 2 relief will include a one-time bill credit to resolve arrears through May 1, 2022 for approximately 75 percent of residential non-EAP and small business customers, and partially resolve arrears for approximately 25 percent of remaining customers. In total, the Phase 2 program provided approximately $73 million of one-time bill credits, to eligible customers who did not receive relief under the Phase 1 program. The cost of the Phase 2 program bill credits and carrying costs will be funded by a combination of approximately $3 million in economic development program deferrals, with the remaining balance to be recovered from customers through a surcharge over a six-year period. On February 21, 2023, in accordance with the Phase 2 Order, National Grid submitted a compliance filing and also requested a proposed uncollectible expense reconciliation mechanism in exchange for a future adjustment of the Phase 2 program customer surcharge, which Niagara Mohawk does not expect will have a material impact to the financial statements. It is uncertain as to when the NYPSC will respond to this proposal.

New York Energy Bill Credit

On February 15, 2024, the NYPSC adopted most of the recommendations in the EAP Working Group's New York State Energy Bill Credit Report filed on November 21, 2023, to provide immediate and automatic relief for all residential and non-residential utility customers that pay into the utilities' EAPs. Customers that do not pay into the EAP would not receive a bill credit. The NYPSC authorized the DPS Staff to distribute the $200 million 2023/2024 New York State budget appropriation in accordance with allocations consistent with the calendar year 2022 EAP expenditures. On April 5, 2024, based upon the share of the calendar year 2022 EAP expenditures, National Grid received $51 million of the $200 million New York State budget appropriation.

New York Transmission Projects

CLCPA Phase 1

On November 8, 2021, Niagara Mohawk filed a petition, which was subsequently updated on April 8, 2022, requesting authorization to develop 27 local transmission projects (“Phase 1”) and approval of cost recovery mechanisms for those projects. On July 14, 2022, the NYPSC issued an order determining that 26 of the proposed local transmission projects qualify for treatment as Phase 1 investments and authorized Niagara Mohawk to use its existing net regulatory liabilities to offset the estimated $9 million in revenue requirement associated with the initial Phase 1 Projects that enter service prior to March 31, 2025. The NYPSC also authorized Niagara Mohawk to defer, for future recovery from ratepayers, the operations expenses up to $1 million associated with the development of subsequent Phase 1 projects through fiscal year 2025, with the expectation that cost recovery will transition into base rates in Niagara Mohawk's next rate filing.

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 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, finding the projects were well supported under the criteria established by the NYPSC that considered, among other factors, incremental transmission capacity, curtailment risk, and costs.

Smart Path Connect

On August 12, 2022, the NYPSC approved National Grid and the New York Power Authority’s (“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. The NYPSC found the project will improve the reliability and economy of the electric system and provide increased transmission capability for renewable resources required to meet the State’s obligations under the CLCPA.

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 return on equity (“ROE”) of 10.3% for the SPC Project, a transmission incentive in the form of recovery of 100 percent of prudently incurred costs for construction work in progress in rate base, and the statewide cost allocation agreement for the SPC project all effective April 1, 2023. FERC had previously approved Niagara Mohawk’s request for the 100% abandonment incentive effective March 2022. 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 proceedings began in August 2023 and are on-going at the present time. FERC allowed the proposed project rate (including the cost containment proposal) to go into effect April 1, 2023, subject to refund pending the outcome of the hearing and settlement procedures.

At March 31, 2024, Niagara Mohawk had SPC related investment of $303 million on its balance sheet.

The New York Gas Companies

Rate Case Filing

On April 28, 2023, the Brooklyn Union Gas Company and KeySpan Gas East Corporation (the "New York Gas Companies") filed to increase revenues by $414 million and $228 million, respectively for the twelve months ending March 31, 2025 ("Rate Year 1"). While the New York Gas Companies' filings propose new rates for Rate Year 1 only, cost data for three additional years have been included to facilitate a potential multi-year settlement. On June 30, 2023, the New York Gas Companies filed Corrections and Updates to their April 2023 filing. The net impact of the Corrections and Updates is an increase of $36 million to the Brooklyn Union Gas Company's revenue requirement and an increase of $44 million to KeySpan Gas East Corporation's revenue requirement. In September 2023, the New York Gas Companies submitted a notice of impending settlement negotiations along with a request to extend the suspension period (with a make whole provision) to facilitate those negotiations.

On April 9, 2024, the DPS, the New York Gas Companies and other parties to the settlement filed a Joint Proposal ("DSNY-JP1") for a three-year rate plan beginning April 1, 2024 and ending March 31, 2027. To reduce rate volatility to customers over the term of the rate plan, the rate increases will be implemented on a levelized percentage basis, estimated to be an annual total bill increase of 10.5% for the Brooklyn Union Gas Company and 9.4% for KeySpan Gas East Corporation.

The DSNY-JP1 supports the goals of the CLCPA and includes provisions for a ramp-up of energy efficiency, demand response, geothermal, and electrification options to meet customers' energy needs while minimizing the need for additional gas infrastructure. In addition, the DSNY-JP1 provides additional resources to promote the New York Gas Companies energy affordability programs and enhanced customer protections for financially vulnerable customers. The DSNY-JP1 proposes a 9.35% ROE and a ratemaking capital structure that reflects a common equity component of 48% for the New York Gas Companies. The rate plans propose that customers will share earnings in excess of 9.85% with earnings above 10.35% applied to the Environmental response costs deferral.

The DSNY-JP1 proposes a Make Whole provision to permit the New York Gas Companies to recover the revenue shortfall resulting from the extension of the suspension period compared to if rates had gone into effect on April 1, 2024. The New York Gas Companies expect an Order from the NYPSC on its rate case filing in the second quarter of fiscal year 2025.

General Rate Case

On May 14, 2021, the DPS Staff and the New York Gas Companies filed a Joint Proposal ("DSNY-JP2") for a three-year rate plan beginning April 1, 2020 and ending March 31, 2023. The total revenue increases are 0% in Rate Year 1 for the New York Gas Companies and 2% and 1.8% in Rate Year 2 and Rate Year 3 for the Brooklyn Union Gas Company and KeySpan Gas East Corporation, respectively. To mitigate the potential bill impacts on customers, the settlement applies nearly $100 million of credits over the three years of the rate plan. In addition, the revenue requirements include amounts from the amortization of excess federal Accumulated Deferred Income Taxes ("ADIT"), which was also used to benefit customers by mitigating rates.

The DSNY-JP2 addresses the goals of the CLCPA and includes provisions that promote energy efficiency, demand response, geothermal, and electrification options to meet customers' energy needs while minimizing the need for additional gas infrastructure. The settlement is based upon an 8.8% ROE and 48% common equity ratio and includes an earnings sharing mechanism with customers when the New York Gas Companies' ROE is in excess of 9.3%. In addition, the DSNY-JP2 also includes a mechanism that would allow the New York Gas Companies to extend the rate plan by twelve months ("Stayout Period"), such that new rates would become effective April 1, 2024. On August 12, 2021, the NYPSC approved and adopted the DSNY-JP2 and supporting schedules with limited additional requirements.

Beginning April 1, 2023, the New York Gas Companies began the Stayout Period which continued the provisions of the current rate plan with some modifications, including the deferral of incremental revenue requirement over the allowance in base rates for the net utility plant and depreciation expense reconciliation mechanism (capped at forecast levels) and Commission-approved energy efficiency costs not recovered in base rates to achieve energy efficiency targets (not to exceed the authorized budget) for the twelve months ended March 31, 2024. On June 22, 2023, the NYPSC approved the New York Gas Companies gas tariff amendments to become effective on a permanent basis to effectuate the Stayout period rates, which provides annual revenue increases of 3.9% and 0.5% for the Brooklyn Union Gas Company and KeySpan Gas East Corporation, respectively.

Proceeding on Energy Affordability Programs and Effects of COVID-19 on Utility Service

COVID-19 Recovery

Refer to "COVID-19 Recovery" section under Niagara Mohawk.

Different from Niagara Mohawk, on June 16, 2022, the NYPSC approved the New York Gas Companies petition for alternative recovery mechanism of COVID-19 unbilled fees, whereby, the Brooklyn Union Gas Company and KeySpan Gas East Corporation will collect its deferral for Rate Year 1 of $13 million and $6 million through a surcharge effective July 1, 2022, through June 30, 2023, respectively. Accordingly, the Brooklyn Union Gas Company and KeySpan Gas East Corporation recorded the revenue related to the COVID-19 unbilled fees deferral, in fiscal year 2023, of $21 million and $10 million to revenue from ARPs and the associated interest income of $2 million and $1 million on the deferral to other income, net, respectively.

Energy Affordability Programs

Phase 1 Arrears Reduction Program

Refer to "Phase 1 Arrears Reduction Program" section under Niagara Mohawk.

Different from Niagara Mohawk, the order authorized the implementation of the Phase 1 Arrears Reduction Program, whereby, the Brooklyn Union Gas Company and KeySpan Gas East Corporation's total EAP arrears reduction one-time bill credits are to be funded by approximately $10 million and $1 million from the New York State budget allocation, a shareholder contribution of $1.2 million and $0.4 million under the Brooklyn Union Gas Company and KeySpan Gas East Corporation's approved petition for alternative recovery mechanism of COVID-19 unbilled fees, with the remaining balance to be recovered from customers through a surcharge over a three and a half year and twelve month recovery period effective on August 1, 2022, respectively. The Brooklyn Union Gas Company and KeySpan Gas East Corporation issued a total of approximately $50 million and $5 million of Phase 1 EAP one-time bill credits to its gas customers for the program, respectively.

Phase 2 Arrears Reduction Program

Refer to "Phase 2 Arrears Reduction Program" section under Niagara Mohawk.

Different from Niagara Mohawk, in total, the Phase 2 program provided approximately $82 million and $17 million of one-time bill credits, to eligible customers who did not receive relief under the Phase 1 program, respectively. For the Brooklyn Union Gas Company, the cost of the Phase 2 program bill credits and carrying costs will be funded by customers through a customer surcharge over an eleven-year period. For KeySpan Gas East Corporation, the cost of the Phase 2 program bill credits and carrying costs will be funded by a combination of approximately $1 million in economic development program deferrals, with the remaining balance to be recovered from customers through a customer surcharge over a three-year period.

New York Energy Bill Credit

Refer to "New York Energy Bill Credit" section under Niagara Mohawk.

The Massachusetts Electric Companies

Rate Case Filing

On November 16, 2023, the Massachusetts Electric Company and its affiliate, Nantucket Electric, filed an application for new base distribution rates to become effective October 1, 2024. The Massachusetts Electric Company and Nantucket Electric's petition requests an overall net increase in base distribution revenue of approximately $131 million based upon a 10.5% ROE, and a capital structure of 53.48% equity, 46.47% long-term debt, and 0.05% preferred stock. The proposed increase includes an increase in annual funding of the storm fund from $16 million to $53 million per year and $7 million per year related to exogenous property tax expenses previously approved and deferred for future recovery. The net increase in base distribution revenue was updated to $123 million in the revised revenue requirements and bill impacts filed on May 3, 2024.

Also included in the petition is the Massachusetts Electric Company and Nantucket Electric's five-year Comprehensive Performance and Investment Plan or "CPI Plan", which encompasses the Massachusetts Electric Company and Nantucket Electric's core investment plan, investments to deliver the clean energy transition, and performance metrics to hold the Massachusetts Electric Company and Nantucket Electric accountable to its CPI Plan. The CPI Plan includes two methods of cost recovery: (1) five-year performance-based ratemaking for operating costs only ("PBR-O") plan, which adjusts non-capital related components of base distribution revenue annually based on a pre-determined formula, plus recovery of incremental capital-related operating expense, and exogenous event costs if applicable; and (2) an Infrastructure, Safety, Reliability and Electrification or "ISRE" mechanism for the annual recovery outside of base rates related to both core capital investment post-test year and any incremental costs associated with the Massachusetts Electric Company and Nantucket Electric's "Future Grid" plan to be reviewed by the DPU in the separate Electric Sector Modernization Plan ("ESMP") proceeding. Both the PBR-O and ISRE recovery mechanisms include the potential to earn incentive revenues and/or penalties as determined annually by the Massachusetts Electric Company and Nantucket Electric's actual performance against a suite of symmetrical performance metrics. The PBR-O mechanism also includes recovery of exogenous events which meet a significance threshold of $4 million, including separate recovery factors related to exogenous storm costs for single storm events greater than $30 million as well as a new proposed exogenous debt cost recovery factor which would refund or collect from customers the difference between actual debt costs incurred and the level of debt cost recovery embedded in base distribution rates annually. The PBR-O proposal includes an earnings sharing mechanism, under which the Massachusetts Electric Company and Nantucket Electric would share 75% of its earnings that exceed 11.5% return on equity with customers. If approved, the Massachusetts Electric Company and Nantucket Electric would agree not to file for an effective change in base distribution rates outside of the annual PBR-O and ISRE mechanisms for a period of five years from the effective date of new rates.

In addition to the base request of $123 million and CPI plan, the Massachusetts Electric Company and Nantucket Electric have petitioned for three additional proposals outside of its base distribution rates. The first is an extension of the storm fund replenishment factor through September 2029 as well as an increase of approximately $13 million to the annual funding level. The Massachusetts Electric Company and Nantucket Electric have also petitioned to extend the term of its Vegetation Management Pilot through September 2029. Finally, the Massachusetts Electric Company and Nantucket Electric have proposed revisions to its current low-income discount rate structure for customers earning 60% of the state median income or less, from the current flat discount rate of 32% to a tiered structure with discounts ranging from 32% to 55%, depending on income and energy burden. The low-income proposal also includes a dedicated team to engage eligible customers through in-person events and a targeted outreach to increase program participation. Recovery of the increased discounts along with costs of increased education and outreach activities would occur through the Massachusetts Electric Company and Nantucket Electric's existing Residential Assistance Adjustment Factors once the program is implemented.

The new base distribution rates would be reflected on customers' bills starting November 1, 2024. To ensure the Massachusetts Electric Company and Nantucket Electric invests, operates, and maintains its distribution system wisely, the proposal will undergo a prudency review by the DPU over a statutory 10-month period and will provide for public input and comment. Public hearings were held in March, April and May 2024 across the service territory. Evidentiary hearings were concluded May 2024 and an order is expected in September 2024.

PBR Plan Filing

On June 15, 2021, the Massachusetts Electric Company and Nantucket Electric filed the second annual PBR plan filing for rates effective October 1, 2021. The PBR plan filing adjusts base distribution rates pursuant to a revenue cap formula, provides a credit to customers for any customer share of excess earnings pursuant to the earnings sharing mechanism, and recovers from or credits customers for the impact of costs in excess of a threshold associated with exogenous events, including storms having incremental costs in excess of $30 million. On September 8, 2021, the DPU allowed the Massachusetts Electric Company and Nantucket Electric's proposed PBR Adjustment and Capital Expenditure Adjustment for effect October 1, 2021, subject to further investigation and reconciliation. On February 23, 2022, the DPU gave final approval to the Massachusetts Electric Company and Nantucket Electric's second annual PBR plan filing for rates that went into effect October 1, 2021, a total increase to base distribution revenue of 2.71%, or $23 million.

On June 17, 2022, the Massachusetts Electric Company and Nantucket Electric filed the third annual PBR plan filing for rates effective October 1, 2022. The Massachusetts Electric Company and Nantucket Electric requested approval of a PBR adjustment of $44 million, based on a PBR percentage of 4.92%. This adjustment reflects the implementation of the Massachusetts Electric Company and Nantucket Electric's proposed voluntary one-time customer impact mitigation plan, which the Massachusetts Electric Company and Nantucket Electric proposed due to the extreme economic circumstances and high inflation rates currently impacting customers. On September 26, 2022, the DPU approved the Massachusetts Electric Company and Nantucket Electric's proposed PBR adjustment and customer impact mitigation plan, effective October 1, 2022. The DPU also stated that it will conduct its review of the Massachusetts Electric Company and Nantucket Electric's proposed amortization of the exogenous storm event with incremental costs in excess of $30 million as part of the Massachusetts Electric Company and Nantucket Electric's next PBR plan filing.

The Massachusetts Electric Company and Nantucket Electric made its fourth annual PBR filing on June 15, 2023. The filing requested a PBR Adjustment for effect October 1, 2023 of $67 million, plus recovery of $14 million annually over five years associated with an exogenous storm event in which the Massachusetts Electric Company and Nantucket Electric incurred incremental costs in excess of $30 million, resulting in a total of $80 million. The filing included a voluntary Customer Impact Mitigation Plan, that reduced what the Massachusetts Electric Company and Nantucket Electric would have otherwise requested under its PBR formula by $15 million, from $81 million to $67 million (not inclusive of the storm event costs). The filing also included a request to approve the recovery method for increased local property taxes due to a change in the assessment methodology, which the DPU previously determined was an "exogenous event" under the PBR tariff, and to recover the ongoing yearly impacts of this change ($7 million for the year ended March 31, 2022 and $1 million for the year ended March 31, 2023).

On September 28, 2023, the DPU approved the Massachusetts Electric Company and Nantucket Electric's proposed PBR Adjustment and Customer Impact Mitigation Plan, as well as the proposed exogenous storm cost recovery factors, effective October 1, 2023. The DPU also approved recovery of the ongoing incremental property tax as requested pertaining to the years ended March 31, 2021 and March 31, 2022.

On June 14, 2024, the Massachusetts Electric Company and Nantucket Electric filed its fifth annual PBR filing, proposing to recover two exogenous storms with incremental costs in excess of $30 million in the storm factor effective October 1, 2024 as allowed by the PBR Provision, equating to recovery of approximately $16 million annually over 5 years.

Tax Act

On November 21, 2019, the FERC issued Order 864 to address ratemaking and regulatory reporting of excess or deficient Accumulated Deferred Income Taxes ("ADIT") related to the Tax Act. On June 29, 2020, NEP, on behalf of the Massachusetts Electric Company and Nantucket Electric, submitted a compliance filing to address the application of Order 864 in NEP's Tariff No. 1. The filing proposed changes to various revenue requirement calculations in the tariff for the inclusion of the rate adjustment and income tax allowance mechanisms. The filing also included the populated permanent ADIT worksheet, which will be provided with the issuance of final bills pursuant to the provisions of the tariff. NEP has proposed for the Massachusetts Electric Company and Nantucket Electric to amortize transmission-related, protected property-related excess or deficient ADIT associated with the 2017 Tax Act using the average rate assumption method, and a 21-year amortization period for unprotected property-related excess or deficient balances. Other unprotected excess or deficient ADIT is proposed to be amortized over five years, consistent with the time period approved in the DPU docket addressing the Tax Act. Following discussions with FERC staff, NEP made a supplemental compliance filing on the Massachusetts Electric Company and Nantucket Electric's behalf on July 19, 2022, in which it proposed adjustments to the initial filing to add greater clarity and transparency. NEP, on behalf of the Massachusetts Electric Company and Nantucket Electric, submitted a supplement to the amended compliance filing on October 3, 2022, based on further discussions with FERC staff. On October 25, 2022, FERC issued an order accepting the Massachusetts Electric Company and Nantucket Electric's compliance filings related to application of Order 864 in Tariff No. 1.

Grid Modernization Plan

On August 19, 2015, the Massachusetts Electric Company, together with Nantucket Electric, filed their first proposed grid modernization plan ("GMP") with the DPU. On May 10, 2018, the DPU issued an order approving $82 million in grid-facing investments over three years (and subsequently, the DPU extended the GMP to a fourth year) in (1) conservation voltage reduction and volt/volt-amps reactive optimization; (2) advanced distribution automation; (3) feeder monitors; (4) communications and information/operational technologies; and (5) advanced distribution management/distribution supervisory control and data acquisition. The DPU allowed recovery of both O&M expenses and capital costs through a reconciling mechanism. The DPU did not approve any customer-facing (i.e., AMI) investments; the DPU said it would address these in a further investigation (which it did in the Massachusetts Electric Company and Nantucket Electric's GMP for calendar years 2022-2025, see below). The Massachusetts Electric Company, together with Nantucket Electric have filed annual reports and cost recovery filings with the DPU for its GMP in 2019, 2020, 2021, 2022 and 2023.

The Massachusetts Electric Company, together with Nantucket Electric filed its proposed four-year GMP (for calendar years 2022–2025) on July 1, 2021, which included proposals to continue the previously-approved investments (designated as "Track 1" in the proceeding), invest in a distributed energy resource management system ("DERMS"), conduct two demonstration projects, and deploy AMI (all designated as "Track 2" in the proceeding). On October 7, 2022, the DPU issued its final order on Track 1, preauthorizing a $301 million budget in (1) monitoring and control ($4 million); (2) volt/volt-amps reactive optimization ($76 million); (3) advanced distribution automation ($38 million); (4) an advanced distribution management system ($61 million); (5) information/operational technology ($19 million); and (6) communications ($103 million) for the 2022-2025 GMP. On November 30, 2022, the DPU issued its Track 2 Order, preauthorizing $35 million in new grid-facing investments for the years 2022-2025 grid modernization plan. Accelerated cost recovery for these investments will continue through the separate grid modernization factor. The DPU also has preauthorized $391 million in spending for our AMI "core" investments for the years 2023-2027, and created a new AMI factor for accelerated cost recovery for these costs. The DPU separated some of the AMI investments into a new category of "supporting" AMI investments and provided preliminary approval for a budget of $96 million for these investments. On March 15, 2024, the Massachusetts Electric Company, together with Nantucket Electric made their first annual AMI cost recovery filing for calendar year 2023, which seeks recovery of $4 million in O&M costs for calendar year 2023. The filing also provides an update on calendar year 2023 program implementation. The Massachusetts Electric Company plans to complete its AMI implementation by the end of 2027.

On April 1, 2022, the Massachusetts Electric Company filed with the DPU its four-year Grid Modernization Term Report, which reports on the Massachusetts Electric Company's implementation of its Grid Modernization Program for calendar years 2018-2021. The DPU also consolidated into this proceeding the Massachusetts Electric Company's annual grid modernization cost recovery filings for calendar years 2018-2021, and is conducting a final review of the costs in this proceeding.

On January 12, 2024, the DPU changed the Grid Modernization annual report filing deadline from April 1st to July 1st, in order to allow the companies time to present "final, audited" cost information in the annual reports. On March 15, 2024, the Massachusetts Electric Company made its GMP cost recovery filing for calendar year 2023, seeking recovery of a $20 million revenue requirement, with total costs for calendar year 2023 of $101 million. The filing provides a brief update on program implementation for calendar year 2023. Overall the program remains on track, a full update will be provided in the calendar year 2023 Grid Modernization annual report which is due to the DPU on July 1, 2024.

COVID-19 Moratorium on Utility Shut Offs

Between March 24, 2020 and February 26, 2021, the Chairman of the DPU declared a moratorium prohibiting all residential utility collection activities due to the COVID-19 pandemic until July 1, 2021. Effective July 1, 2021, the Massachusetts Electric Company recommenced normal collections activities, which includes issuing notices of amounts in arrears and alerting customers that their service is subject to disconnection for non-payment. Transitional extended deferred payment arrangements were, however, in place through May 2022, and more flexible terms for the arrearage management program (e.g., an increase in arrearages forgiven from $4,000 to $12,000) are still in effect. The commercial and industrial moratorium was lifted effective September 1, 2020.

On December 31, 2020, the DPU approved the following implementation items related to the ratemaking treatment of the COVID-19 customer assistance programs on which the Massachusetts local distribution companies and the Massachusetts Attorney General's ("AG") office had reached consensus: (1) the distribution companies should be allowed to record, defer and track their bad debt and other COVID-related expenses; (2) cost recovery should be limited to the incremental costs incurred; and (3) certain costs must be extraordinary to qualify for recovery. As of March 31, 2023 and March 31, 2024, the Massachusetts Electric Company has deferred $27 million of delivery bad debt (for both the Massachusetts Electric Company and Nantucket Electric) and $1 million of other COVID-related costs, as the Massachusetts Electric Company believes that these amounts are probable of recovery.

The DPU decided that the contested issues, including the extent to which the distribution companies will be allowed to recover their COVID-19 costs, should be fully adjudicated in a new docket, D.P.U. 20-91. The AG opposes recovery by distribution companies with PBR plans (including the Massachusetts Electric Company, together with Nantucket Electric) of incremental COVID-related O&M expenses. The AG also opposes using the pre-tax overall weighted cost of capital for the calculation of carrying charges on bad debt, arguing that the short-term debt rate, or, in the alternative, an interest rate contemporaneous to two-year U.S. Treasury notes, is the correct rate. The AG also takes the position that the DPU should consider the significance of the distribution companies' net incremental O&M costs due to COVID-19 to determine whether they resulted in substantial harm to the distribution companies' financial position. The briefing phase has concluded, and the DPU's order is pending. The Order will likely be issued after August 2024 when the Distribution Companies submit their final report on bad debt levels through June 30, 2024. The Distribution Companies were required to track delivery-related bad-debt write-offs for two years, from July 1, 2020 through June 30, 2022, and filed a report on August 1, 2022, reporting incremental delivery-related net charge offs. The Massachusetts Electric Company and Nantucket Electric are required to continue to track bad-debt write-offs for the two-year period of July 1, 2022 through June 30, 2024, with a report to be filed on August 1, 2024, depending on each utility's timing of base distribution rate case filings, and to submit filings to the DPU after that point to commence recovery of the demonstrated incremental amount.

Massachusetts Petition for Waiver of Jurisdiction Regarding the Rhode Island Sale

On May 3, 2021, PPL Energy Holdings, LLC assigned its right to acquire Narragansett to its wholly owned subsidiary, PPL Rhode Island Holdings, LLC ("PPL Rhode Island"), such that, upon closing, PPL Rhode Island owned 100% of the outstanding shares of common stock in Narragansett. The DPU approved NGUSA's request for a waiver of G.L. c. 164, § 96(c), regarding the sale of Narragansett in July 2021. Following that approval there was an appeal process which concluded in May 2022 with a settlement agreement with the AG and on May 25, 2022, Narragansett was sold to PPL Rhode Island.

On June 24, 2022, the Massachusetts Electric Company and Nantucket Electric submitted their compliance filing per directives in the DPU's July 16, 2021, order as well as commitments in the AGO Settlement to issue a one-time bill credit to customers. On July 26, 2022, the DPU approved the Massachusetts Electric Company and Nantucket Electric's bill credit proposal and compliance filing. The one-time bill credit was refunded to customers through their bills over six months period from November 2022 to April 2023. On June 30, 2023, the Massachusetts Electric Company and Nantucket Electric made a filing on the annual report with the AG and DPU in accordance with Section 2.13 of the Settlement. The Massachusetts Electric Company and Nantucket Electric also provided information related to the annual report requirements as part of the Cost Mitigation Report submitted with the rate filing on November 16, 2023. Review of the cost mitigation report by the DPU and AG will occur in the context of the rate case.

Storm Threshold Deferral Requests

On June 17, 2022, the Massachusetts Electric Company and Nantucket Electric petitioned the DPU for authorization to defer for future recovery $6 million in storm cost threshold amounts associated with four qualifying major storm events that occurred in calendar year 2021. On January 19, 2023, the DPU issued an order allowing the Massachusetts Electric Company and Nantucket Electric to apply deferral accounting treatment to threshold amounts associated with three major storm events, totaling $5 million. The DPU disallowed $2 million of threshold costs associated with the October 26, 2021 Wind/Rain Event because it would be considered as an exogenous event. The DPU will determine the appropriate level of recovery for the excess storm fund threshold amount (if any) in the Massachusetts Electric Company and Nantucket Electric's next base distribution rate case. On June 15, 2023, the Massachusetts Electric Company and Nantucket Electric petitioned the DPU for authorization to defer for future recovery $6 million in storm cost threshold amounts associated with four qualifying major storm events that occurred in calendar year 2022. Briefing concluded on October 24, 2023. On November 13, 2023, the DPU issued an order allowing the Massachusetts Electric Company and Nantucket Electric to apply deferral accounting treatment to the four storm thresholds. The Massachusetts Electric Company and Nantucket Electric have sought recovery of deferred amounts in its current rate case petition. The DPU will determine what if any recovery is appropriate in its rate case order. On June 14, 2024, the Massachusetts Electric Company and Nantucket Electric requested deferral accounting treatment of 8 storm thresholds for events in calendar year 2023 for a total of $12 million until the storm cost recovery filing to be made in 2025.

Storm Cost Recovery

On September 26, 2019, the Massachusetts Electric Company and Nantucket Electric submitted a cost recovery filing to the DPU for three storms from in 2017 and 2018 totaling $103 million in incremental O&M costs pursuant to the storm fund. On November 27, 2023, the DPU issued an order approving $100 million in requested costs, disallowing $3 million due to insufficient documentation and unrelated storm costs. On January 11, 2024, the Massachusetts Electric Company made an original compliance filing to recalculate costs for storm fund recovery based on the revised capitalization methodology approved in D.P.U. 18-94-A and calculated consistent with D.P.U. 18-94 and D.P.U. 18-153. The total net incremental O&M deferred storm costs was decreased by $19 million, comprised of $3 million of disallowances, $16 million increase in capital exclusions, and a decrease of $0.2 million in materials exclusions. Due to the calculation revisions, the originally sought amount $103 million was reduced to $84 million, which will result in $3 million of disallowances; the net increase to capital and materials exclusions was recorded as a reclassification from the deferral account to property plant and equipment and will be recovered through rate base in a future base rate filing. The compliance filing was approved on February 12, 2024 without revision. The Massachusetts Electric Company filed a revised compliance filing on May 3, 2024. The storm cost deficit was reduced by $0.3 million as of December 31, 2023.

Municipal Fiscal Year 2022 Property Tax Exogenous Event Request

The Massachusetts Department of Revenue ("DOR") has required municipalities to change the way they calculate property taxes, resulting in property tax increases to the Massachusetts Electric Company and Nantucket Electric. On October 18, 2022, the Massachusetts Electric Company and Nantucket Electric filed to be able to recover the costs of this change as an "exogenous event" under their PBR plan, along with Boston Gas Company. On May 17, 2023, the DPU approved the Massachusetts Electric Company and Nantucket Electric's request to recover incremental fiscal year 2022 property tax expenses due to certain municipalities changing their assessment methodology after DOR changed its certification standards. The approved amount was $7 million for the Massachusetts Electric Company and Nantucket Electric. The Massachusetts Electric Company and Nantucket Electric were directed to propose a recovery method for the approved amounts in the next PBR filing due on June 15, 2023. After a favorable ruling in a separate case allowing Eversource Energy to recover these type of incremental property taxes, the Massachusetts Electric Company and Nantucket Electric added a request to recover fiscal year 2021 incremental property taxes in the proceeding, but the DPU did not allow this request because it was not part of the initial filing and notice in the proceeding. The Massachusetts Electric Company and Nantucket Electric requested recovery of these fiscal year 2021 amounts and fiscal year 2023 incremental costs in its PBR filing made June 15, 2023. On September 28, 2023, the DPU approved the Massachusetts Electric Company and Nantucket Electric's recovery proposal pertaining to fiscal years 2021 and 2022 incremental property tax expense. Recovery of fiscal year 2023 incremental property tax expense was disallowed, as the annual incremental expense incurred of $0.6 million did not meet the significance threshold for exogenous recovery under the current PBR provision. The Massachusetts Electric Company and Nantucket Electric sought approval to defer the recovery of $40 million associated with the cumulative annual increase to its property taxes for fiscal years 2021 through 2023 and to recover $8 million each year over a five-year period beginning on October 1, 2024. The DPU approved the Massachusetts Electric Company and Nantucket Electric's proposal, and consistent with the disallowance of the fiscal year 2023 incremental property tax costs above, reduced the amount of recovery to $39 million or $8 million each year.

As of March 31, 2024, Massachusetts Electric deferred $39 million to regulatory assets for both Nantucket Electric and Massachusetts Electric which resulted in the reduction of property tax expense in the current year.

Electric Sector Modernization Plan

G.L. c. 164, Sections 92B and 92C, requires each electric distribution company to develop ESMP to proactively upgrade the distribution system to help the Commonwealth realize its statewide greenhouse gas (“GHG”) emissions limits and sublimits under Chapter 21N. On January 29, 2024, the Massachusetts Electric Company filed its ESMP with the DPU. Per the DPU’s February 20, 2024 Interlocutory Order on Scope of Proceedings, the DPU will investigate these first ESMP filings as strategic plans and in that context will investigate compliance with the statute, the electric distribution companies’ (“EDCs”) forecast methods and net benefits proposals, the appropriate cost recovery framework (base rates or a reconciling mechanism), and the standard of review, and will defer performance metrics to a subsequent phase of the proceedings. The DPU will not adjudicate budget pre-approval requests (including for new CIPs) or cost allocation or rate design proposals. The statute requires the DPU to issue an order by August 29, 2024.

The Boston Gas Company

General Rate Case

On November 13, 2020, the Boston Gas Company filed a rate case with the DPU, including a request for approval of a PBR Plan and related proposals. The Boston Gas Company requested that the DPU approve new distribution rates to increase distribution revenues by $221 million, including the transfer of $82 million of recovery of the Boston Gas Company’s Gas System Enhancement Program (“GSEP”) investments completed through March 31, 2020, from the GSEP factors to base distribution rates, with new rates to be effective October 1, 2021. The actual net revenue deficiency calculated by the Boston Gas Company for distribution rates is $139 million, or an incremental increase in distribution revenue of 18.1%.

On September 30, 2021, the DPU issued an Order in the Boston Gas Company’s rate case. The Order allowed an increase in base revenues of $145 million. On October 20, 2021, the Attorney General filed a motion for recalculation. On October 22, 2021, the Boston Gas Company filed a motion for recalculation and reconsideration. On November 17, 2021, the DPU issued its Order on those motions which reduced annual base distribution revenues to $142 million effective December 1, 2021. DPU authorized an ROE of 9.70%, raised from the previous ROE of 9.50%. The Order also authorized a capital structure of 53.44% equity and 46.56% debt. The DPU approved a five-year PBR plan for the Boston Gas Company which is applicable to both core capital expenditures and operational expenditures, and which allows the Boston Gas Company to adjust revenues each year for inflation, adjusted by a productivity factor and consumer dividend. As part of the PBR Plan, the DPU approved cost recovery for certain exogenous events where an individual event’s cost change is over $2 million annually, and also approved an Earnings Sharing Mechanism, pursuant to which the Boston Gas Company will share 75% of excess earnings with customers set to begin at 200 basis points over the allowed ROE of 9.70%. The DPU allowed for recovery of the costs of 133 new employees hired after the end of the test year in the case and approves an adjustment to base distribution rates to reflect the recovery of capital additions after the test year through December 31, 2020. The Order also permits the Boston Gas Company to make a request for a one-time adjustment to its allowance in rates for the recovery of LNG investments, at a point in the 5-year PBR term chosen by the Boston Gas Company. On June 14, 2024, the Boston Gas Company made the one-time initial filing to recover the costs of its LNG investments from April 1, 2020, through March 31, 2024. The total investment for which recovery is being sought is $132 million. The revenue requirement for these investments is $19 million.

PBR Plan Filing

On June 17, 2022, Boston Gas Company filed the first annual PBR plan filing for rates effective October 1, 2022. The Boston Gas Company requested approval of a base distribution rate adjustment effective October 1, 2022 of approximately $64 million based on a PBR Percentage of 4.80% and a one-time adjustment for certain investment during the period April 2020 through December 2020. The PBR Percentage is the result of implementing the Boston Gas Company’s proposed one-time Customer Impact Mitigation Plan, which the Boston Gas Company proposed due to the extreme economic circumstances currently impacting customers at this time. In the absence of the Customer Impact Mitigation Plan, the Boston Gas Company would be proposing a base distribution rate adjustment of $77 million based on a PBR Percentage of 6.35% and the capital investment adjustment noted above, in accordance with the PBR Tariff. On September 26, 2022, the DPU approved the Boston Gas Company's proposed base distribution rate adjustment and Customer Impact Mitigation Plan.

The Boston Gas Company made its annual PBR filing on June 15, 2023. The filing requests a PBR Adjustment for effect October 1, 2023 of approximately $57 million. It includes a voluntary Customer Impact Mitigation Plan by the Boston Gas Company in light of continuing high inflation; the mitigation plan reduces what the Boston Gas Company would have otherwise requested under its PBR formula by $14 million, from $71 million to $57 million. The filing also includes a request to approve the recovery method for increased local property taxes due to a change in the assessment methodology, which the DPU previously determined was an "exogenous event" under the PBR tariff, and to recover the ongoing yearly impacts of this change ($4 million for the year ended March 31, 2022 and $0.2 million for the year ended March 31, 2023). On September 28, 2023, the DPU approved the Boston Gas Company's proposed base distribution rate adjustment and Customer Impact Mitigation Plan. The DPU also approved recovery of incremental property taxes for fiscal years 2021 and 2022 as proposed. Incremental property taxes for fiscal year 2023 were disallowed as the annual impact of $0.2 million did not meet the significance threshold for exogenous recovery under the Boston Gas Company's current PBR provision.

The Boston Gas Company made its third annual PBR filing on June 14, 2024. The filing requests a PBR Adjustment for effect October 1, 2024, of approximately $41 million based on a PBR percentage of 4.4%. The Boston Gas Company also seeks approval to update the volumetric billing determinants for its residential heating rate classes from calendar year 2020 billing determinants to calendar year 2023 billing determinants to reflect in its rate design the lower weather-normalized usage the Boston Gas Company has experienced over the past several years. In addition, the Boston Gas Company provides a progress report on its PBR scorecard metrics, which includes an update to its methane emission metrics for calendar year 2022 and a baseline for its Grade 3 leak backlog metric.

Everett Marine Terminal LNG Contract

On February 9, 2024, the Boston Gas Company filed for the DPU's approval of a six-year agreement with Constellation LNG, LLC for LNG service from Everett Marine Terminal, requesting an Order by May 1, 2024. Constellation requested that the DPU complete its review of contracts for supply from the Everett Marine Terminal by May 1, 2024, to assure ongoing commercial operation of the facility after expiration of the Mystic Cost of Service Agreement with ISO-New England on May 31, 2024. The briefing period concluded on April 23, 2024. On April 24, 2024, Constellation submitted a letter to the DPU informing parties that it did not anticipate executing agreements for the required maximum seasonal quantity that Constellation deemed necessary to keep the Everett Marine Terminal open and, as a result, it would need to change to a certain price term to avoid having to exercise its termination right. On April 25, 2024, the Boston Gas Company responded that given the important reliability benefits provided by the agreement, the Boston Gas Company continues to request the DPU's approval, and that Constellation's proposed price change resulted in a minimal bill increase compared to the original agreement's pricing. Comments in response to Constellation's letter and the Boston Gas Company's response were submitted by Conservation Law Foundation on May 2, 2024. On May 15, 2024, the Boston Gas Company and the other local gas distribution companies ("LDCs") filed amendments extending certain dates in the agreement. On May 17, 2024, the DPU issued an order approving the Constellation agreement; the order requires certain periodic reporting requirements.

Gas System Enhancement Plan (GSEP)

On April 28, 2023, the DPU approved the Boston Gas Company's CY2023 GSEP, including recovery of approximately $127 million in revenue requirements, related to anticipated investments in 2023 under an accelerated pipe replacement program, through GSEP. The rates are effective from May 2023 to April 2024. The DPU approved the Boston Gas Company's plan for replacing of leak-prone infrastructure in 2023, finding that the Boston Gas Company's GSEP accomplishes the continued accelerated replacement of leak-prone infrastructure consistent with the requirements of state law.

Specifically, the DPU approved the proposal to replace or abandon 116 miles of leak-prone pipe (LPP) in the legacy Boston Gas service territory, and 14 miles of LPP in the former Colonial Gas service territory; and to line 4 miles of cast iron pipe and repair 870 cast iron joints with CISBOT technology, as well as to spend $2 million to repair Grade 3 Significant Environmental Impact leaks.

On May 1, 2023, the Boston Gas Company filed with the DPU its reconciliation of its GSEP costs from calendar year 2022, and its documentation of the GSEP work completed in calendar year 2022. On October 31, 2023, the DPU issued an order approving the Boston Gas Company's calendar year 2022 GSEP investments. The DPU approved the Boston Gas Company's proposed reconciliation factors to address recovery of the reconciliation balances from the Boston Gas Company's calendar year 2022 investments in its former Colonial Gas Company service territory. The DPU denied the Boston Gas Company's request to waive the 3% incremental recovery cap for its Boston Gas Company GSEP investments, meaning that $19 million of Boston Gas's GSEP investments for calendar year 2022 that are above the cap will not be recovered through this year's GSEP reconciliation factors and will instead be recovered through a future GSEP reconciliation filing or through the Boston Gas Company's next rate case. The DPU directed the Boston Gas Company to implement revised reconciliation factors for Boston Gas, that allow for recovery of Boston Gas's GSEP reconciliation balances below the recovery cap.

On October 31, 2023, the Boston Gas Company filed with the DPU its proposed GSEP plan for calendar year 2024. The proposed plan includes replacing or retiring 134 miles of leak-prone pipe and repairing an estimated 230 Grade 3 Significant Environmental Impact leaks. The plan also proposes that the costs of its second anticipated geothermal pilot be recovered through GSEP. The plan also identifies a targeted electrification non-pipe alternatives pilot project using integrated energy planning, which the Boston Gas Company anticipates filing for the Department's approval during calendar year 2024. The DPU approved the Boston Gas Company's calendar year 2024 GSEP on April 30, 2024.

On May 1, 2024, the Boston Gas Company filed with the DPU its reconciliation of its GSEP costs from calendar year 2023, and its documentation of the GSEP work completed in calendar year 2023. The proposed rate increase exceeds the 3 percent incremental recovery cap for the Boston Gas Company GSEP investments, meaning that $25 million of revenue on the Boston Gas Company's GSEP investments for calendar year 2023 that is above the cap will not be recovered through this year's GSEP reconciliation factors and will instead be recovered through a future GSEP reconciliation filing or through the Boston Gas Company's next rate case. If approved and combined with the amount of calendar year 2022 GSEP investment recovery that exceeded the cap as discussed above, a cumulative $43 million plus interest would be deferred for future recovery of Boston Gas – related GSEP investment.

Gas Business Enablement (GBE) Recovery Mechanism

On October 13, 2023, the DPU issued an order denying the Boston Gas Company's CY2021 GBE costs and suspended the Boston Gas Company's cost recovery mechanism that recovers annual GBE Program implementation costs. In addition to the suspending the cost recovery mechanism the DPU ordered the Boston Gas Company to refund approximately $24 million in total GBE program costs with interest to be calculated at the prime rate as set forth in the Boston Gas Company's LDAC tariff to customers. The DPU did so due to the continued delays of implementation in Massachusetts for gas customers and not the prudency of the documentation submitted. The DPU further stated that the Boston Gas Company may seek recovery of GBE costs through traditional rate making, such as the next gas rate case. On October 30, 2023, the Boston Gas Company filed a Motion for Clarification and Stay of Compliance Filing with the DPU. The Boston Gas Company was seeking clarification from the DPU that the costs refunded are not denied and can be deferred until the next rate case where we can seek recovery of all GBE implementation costs if the full program is in service and used and useful for Massachusetts gas customers. On November 16, 2023, the DPU issued an order denying the Boston Gas Company's Motion for Clarification filed on October 30, 2023, and directed the Boston Gas Company to refund its ratepayers beginning December 1, 2023. Following that ruling, on December 1, 2023, the Boston Gas Company filed a Motion for Reconsideration of the DPU's order along with a Request for Deferral of $70 million, and Motion to Extend Judicial Appeal period.

On March 19, 2024, the DPU issued an Order denying the Boston Gas Company's motion for reconsideration and petition for deferral. The DPU found that the Boston Gas Company should have treated the DPU's October 2023 order suspending the GBE tracker and ordering a refund of amounts previously collected $24 million plus interest as a final order, such that the Boston Gas Company's subsequent motion for reconsideration and petition for deferral was not timely filed. The Boston Gas Company has been directed to make the compliance filing to implement refunds of the $24 million plus interest no later than April 1, 2024. On March 26, 2024, the Boston Gas Company submitted its compliance filing in accordance with the DPU directive to implement refunds of the GBE program costs of $24 million plus interest no later than April 1, 2024. The Department approved the compliance filing of the refund on March 28, 2024. On April 8, 2024, the Boston Gas Company filed a petition for appeal of the DPU's final decision in this docket with the MA Supreme Judicial Court asking the court to vacate the order with instructions to the DPU to conduct appropriate proceedings to review the prudence of GBE program costs in accordance with due process, MA law, and DPU precedent.

Revenue Decoupling Adjustment (RDA)

The Boston Gas Company makes semi-annual filings with the DPU to reconcile revenues according to the revenue decoupling provision. In the Boston Gas Company's filing for effect November 1, 2023 through April 30, 2024, the Boston Gas Company requested a waiver of the Three Percent Revenue Decoupling Cap to recover the full Revenue Decoupling Adjustment of approximately $109 million, thereby eliminating the need to carry a deferral into future periods and eliminating the interest charges on the deferral, estimated at $5 million per year based on the currently effective prime rate. The Department approved the Boston Gas Company's waiver request in its Order issued on October 30, 2023.

Geothermal District Energy Demonstration Program

On December 15, 2021, the DPU approved the Boston Gas Company's petition for a five-year, $16 million geothermal district energy demonstration program. The costs for the demonstration program are recovered through a factor in the Local Distribution Adjustment Factor (LDAF). The program allows the Boston Gas Company to install, own, and operate up to four geothermal shared-loops sites that evaluate one or more of the following: (1) assessing the thermal performance and economics of shared loops serving a larger number of customers with more diverse load profiles than the project completed by the Boston Gas Company's affiliate KeySpan Gas East Corporation on Long Island, New York; (2) switching gas customers to geothermal energy as an alternative to leak-prone pipe replacements; (3) installing shared loops to manage local gas system constraints and peaks; and (4) installing shared loops to lower operating costs and greenhouse gas ("GHG") emissions for low-income customers and environmental justice communities. On May 16, 2022, the Boston Gas Company filed its geothermal energy demonstration program implementation plan for DPU review and approval. On September 13, 2022, the DPU approved the Boston Gas Company's implementation plan. The Boston Gas Company selected the first site project in Lowell, Massachusetts and has been conducting outreach to enroll gas customers in the program. On June 30, 2023, the Boston Gas Company filed its first annual report and associated costs with the DPU. Due to minimal costs incurred during the prior calendar year, the Boston Gas Company proposed to delay review and collection of the 2022 costs until next annual filing to be made by July 1, 2024 in the interest of administrative efficiency. The DPU approved the Boston Gas Company's proposal on August 24, 2023. On January 25, 2024, the Boston Gas Company announced that its second geothermal site will be located in Franklin Fields, Boston working with the Boston Housing Authority.

Investigation into the Future of Natural Gas

On October 29, 2020, the DPU opened an investigation into the role of LDCs in achieving the Commonwealth's 2050 climate goals. The investigation explored strategies to meet the Commonwealth's greenhouse gas emissions reductions targets while ensuring safe, reliable, and cost-effective natural gas service, and potentially recasting the role of gas companies in the Commonwealth. On March 18, 2022, each LDC submitted a proposal to the DPU that included recommendations and plans for helping Massachusetts achieve its 2050 climate goals, supported by an independent consultants' report, that had incorporated feedback and advice obtained through a stakeholder process. Supported by the consultants' analysis, the Boston Gas Company's proposal envisioned meeting the state's 2050 climate goals by utilizing a decarbonized and integrated gas and electric system that: (1) increases investment and adoption of energy efficiency measures, including the prioritization of building envelope; (2) eliminates fossil fuels from our gas supply by pursuing delivery of fossil-free gas such as renewable natural gas and renewable hydrogen through our network to all our customers; (3) enables customer use of hybrid heating by supporting customer adoption of heating technologies best suited to their needs; and (4) utilizes targeted electrification, including new solutions such as networked geothermal where safe and cost-effective. Initial comments by stakeholders on the consultants' report, LDC plans, and any alternative proposals were submitted to the DPU by May 6, 2022, and the discovery period ended June 7, 2022. At the direction of the DPU, the LDCs submitted joint comments responding to stakeholder comments on the consultants' report and LDC proposals on July 29, 2022. Several stakeholders submitted additional comments by the October 14, 2022 deadline.

On December 6, 2023, the DPU issued an order on regulatory principles and a framework to meet the state's climate goals without choosing a preferred decarbonization pathway or technology. While setting forth regulatory principles and future proceedings, the order recognizes the state and federal safety requirement-related investments that the LDCs must make, confirms the GSEP remains unchanged at this time, and does not jeopardize cost recovery of existing, prudent gas system investments. Going forward, LDCs will need to provide evidence as to the prudency of future investments including an analysis of non-pipeline alternatives ("NPA"). The order provides for potential future networked geothermal programs, requires targeted electrification pilots, and allows hydrogen and renewable natural gas pilots for targeted end uses under certain circumstances. The order requires LDCs to change the revenue decoupling mechanism from a revenue per customer to revenue cap approach in its next rate case, and also requires each LDC to file a periodic five-year Climate Compliance Plan, the first of which is due by April 1, 2025, outlining the Boston Gas Company's approach to the decarbonization transition. On December 29, 2023, the gas companies filed joint motions for clarification and extension of the judicial appeal period. The motion for clarification includes the timing and application of the non-pipeline alternative analysis to investment types, how new performance-based ratemaking metrics tied to climate plan objectives are to be incorporated in future rate plans, and certain emissions reduction calculations. Several stakeholders submitted responses to the motion for clarification by the January 22, 2024, deadline.

On April 2, 2024, the DPU issued an order on the motion, which clarifies that the requirement to evaluate NPAs applies to all new gas investments, including safety, reliability, and GSEP, at the project level from the date of the original order on December 6, 2023. The Boston Gas Company must also engage with stakeholders to develop a full NPA framework, including any feasibility or category screens, prior to filing for DPU review. The order also confirms that climate compliance plan metrics must be filed in the Boston Gas Company's next base rate case, regardless of whether the Boston Gas Company proposes a PBR plan, and that the Boston Gas Company must report Scope 1 and 3 GHG emissions in the climate compliance plan.

Municipal Fiscal Year 2022 Property Tax Exogenous Event Request

Refer to "Municipal Fiscal Year 2022 Property Tax Exogenous Event Deferral Request" section under The Massachusetts Electric Companies.

Different from the Massachusetts Electric Companies, the Boston Gas Company requested recovery of these fiscal year 2021 and 2023 incremental costs incurred to date in its PBR filing made June 15, 2023, and, if approved, will include these costs in base distribution rates on a going-forward basis beginning with its 2024 PBR filing with rates effective October 1, 2024. The DPU approved recovery of the fiscal year 2021 and fiscal year 2022 property tax increases as proposed, on September 28, 2023. Recovery of the fiscal year 2023 property tax expense was disallowed as the annual impact did not meet the significance threshold for exogenous recovery under the Boston Gas Company's current PBR provision.

NEP

Stranded Cost Recovery

Under the settlement agreements approved by state commissions and the FERC, NEP is permitted to recover stranded costs (those 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 a ROE related to stranded cost recovery consisting of nuclear-related investments. In Massachusetts and Rhode Island, the current ROEs are 9.2% and 10.46%, respectively. NEP will recover its remaining non-nuclear stranded costs until the costs associated with the decommissioned nuclear units cease.

8. EQUITY METHOD INVESTMENTS

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

	March 31,	
	2024	2023
	(in millions of dollars)	
Community Offshore Wind, LLC ("COSW")	**$ 367**	$ 310
Sunrun Neptune Investor 2016 LLC ("Sunrun")	**133**	131
Emerald	**712**	450
New York Transco LLC ("Transco")	**140**	124
Other	**121**	120
Total equity method investments	**$ 1,473**	$ 1,135

The following table describes the Company's material investments as of March 31, 2024:

Investment Name	Ownership Interest	Description
COSW	27.3%	COSW is a limited liability company formed under the laws of the State of Delaware that focus on the Northeast U.S. offshore wind market. COSW successfully acquired a seabed lease in the northeastern US and has commenced the development of offshore wind, which will play a key role in supplying clean energy to customers in New York.
Sunrun	100%	The Company holds 100% of the Class A shares in San-Francisco based Sunrun, which is a leading U.S. provider of residential solar energy systems. The Company has elected to account for its investment in Sunrun, which would otherwise be accounted for under the equity method of accounting, at fair value with changes in fair value reported as part of 'Income from equity method investments' in the consolidated statements of operations and comprehensive income.
Emerald	51%	Emerald builds and operates wind and solar assets. The Company accounts for its share of the earnings of the projects owned by Emerald using the HLBV method, with changes in the amount allocated to the Company after adjusting for distributions and contributions recorded as income or loss for that period in Income from equity method investments in the consolidated statements of operations and comprehensive income.
Transco	28.3%	Transco was formed to plan, build, own, operate, maintain, and expand transmission facilities in the state of New York.

On October 7th, 2022, National Grid Ventures closed on the sale of its entire 26.25% joint venture interest in Millennium Pipeline Company, LLC for $552 million in cash proceeds. The Company recognized a pre-tax gain of $339 million, net of transaction costs during the year-ended March 31, 2023.

Unconsolidated VIEs

The Company holds varying interests in VIEs, including Emerald, Energy Impact Fund LP ("EIF"), COSW and Passion Capital GC LP. The Company is not the primary beneficiary of these entities as it does not have the power to direct the most significant activities of each entity. The Company accounts for its ownership interest in each entity using the equity method of accounting. The maximum exposure to loss for these unconsolidated VIEs represents the carrying value of the Company's equity method investment as reported on the consolidated balance sheets. There are no other amounts recorded on the Company's consolidated balance sheets in relation to its investments in unconsolidated VIEs. During the years ended March

31, 2024 and 2023, the Company did not provide any financial or other support to the VIEs that it was not contractually obligated to.

9. 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,	
	2024	2023
	(in millions of dollars)	
Plant and machinery	**$ 50,247**	$ 46,259
Assets in construction	**3,984**	3,729
Land and buildings	**2,527**	2,302
Software and other intangibles	**2,992**	2,592
Operating leases ROU assets	**1,293**	1,129
Total property, plant and equipment	**61,043**	56,011
Accumulated depreciation – Tangible assets	**(11,594)**	(10,832)
Accumulated amortization – Software and other intangibles	**(1,642)**	(1,395)
Accumulated amortization – Operating lease ROU assets	**(466)**	(390)
Property, plant and equipment, net	**$ 47,341**	$ 43,394

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 7 to 10 years and commencing upon operational use. Amortization expense for capitalized software was $247 million and $212 million for the years ended March 31, 2024 and 2023, respectively. As of March 31, 2024, amortization expense is estimated to be $266 million, $244 million, $226 million, $198 million, and $166 million for 2025 through 2029, respectively.

10. DERIVATIVE INSTRUMENTS AND HEDGING

The Company utilizes derivative instruments to manage commodity price, interest rate, and foreign currency rate risk associated with its natural gas and electricity purchases, its long-term funding activities and its Euro commercial paper program. The Company's commodity risk management strategy is to reduce fluctuations in firm gas and electricity sales prices to its customers. The Company's currency risk management policy is to borrow in the most advantageous market available, and to hedge the risk associated with foreign currency borrowings by utilizing instruments to convert principal and interest payments into U.S. dollars. The Company's interest rate risk management strategy is to minimize its cost of capital by adjusting the proportion of fixed-rate and floating-rate in the borrowings portfolio to within a range set by the Finance Committee of the National Grid plc Board.

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. The financing derivatives consisted of cross currency interest rate swaps, interest rate swaps and foreign exchange forward contracts of ($4,710) million, and ($3,330) million at March 31, 2024 and 2023, respectively.

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

	March 31,	
	2024	2023
	(in millions)	
Gas contracts (dths)	**160**	129
Electric contracts (mwhs)	**14**	15

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, 2024 and 2023:

	March 31, 2024		
	(in millions of dollars)		
	Gross amount	**Gross amount not offset on the Consolidated Balance Sheet**	**Net amount**
	A	***B***	***C = A-B***
ASSETS:			
Other current assets, net			
Gas contracts	**$ 4**	**$ 2**	**$ 2**
Electric contracts	**33**	**27**	**6**
Other non-current assets, net			
Electric contracts	**9**	**6**	**3**
Interest rate swaps [1]	**81**	**70**	**11**
Total	**$ 127**	**$ 105**	**$ 22**
LIABILITIES:			
Current liabilities			
Gas contracts	**45**	**2**	**43**
Electric contracts	**69**	**27**	**42**
Foreign exchange forward contracts	**12**	**-**	**12**
Interest rate swaps [1]	**33**	**-**	**33**
Other non-current liabilities			
Gas contracts	**2**	**-**	**2**
Electric contracts	**36**	**6**	**30**
Interest rate swaps [1]	**187**	**126**	**61**
Total	**384**	**161**	**223**
Net assets (liabilities)	**$ (257)**	**$ (56)**	**$ (201)**

[1] Consists of cross-currency interest rate swaps and interest rate swaps designated for hedge accounting.

	March 31, 2023		
	(in millions of dollars)		
	Gross amount	**Gross amount not offset on the Consolidated Balance Sheet**	**Net amount**
	A	***B***	***C = A-B***
ASSETS:			
Other current assets, net			
Gas contracts	$ 12	$ 9	$ 3
Electric contracts	57	25	32
Foreign exchange forward contracts	10	7	3
Other non-current assets, net			
Electric contracts	9	3	6
Total	88	44	44
LIABILITIES:			
Current liabilities			
Gas contracts	95	9	86
Electric contracts	70	25	45
Other non-current liabilities			
Gas contracts	5	-	5
Electric contracts	46	3	43
Interest rate swaps [1]	269	167	102
Total	485	204	281
Net assets (liabilities)	$ (397)	$ (160)	$ (237)

[1] Consists of cross-currency interest rate swaps and interest rate swaps designated for hedge accounting.

Effect of Derivative Instruments on Statements of Operations and Comprehensive Income

Changes in fair value of the Company's rate recoverable contracts (commodity contracts only, hedge contracts are not rate recoverable) 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, 2024 and 2023:

	Location	**Year Ended March 31,**	
		2024	2023
		(in millions of dollars)	
Electric contracts	Purchased electricity	**$ (143)**	$ 179
Gas contracts	Purchased gas	**(130)**	(17)
Total gains (losses) recognized in earnings		**$ (273)**	$ 162

The following table summarizes changes in the fair value of commodity derivative instruments not designated as hedging instruments that are offset by change in regulatory assets and liabilities for the years ended March 31, 2024 and 2023:

	Location	Year Ended March 31, 2024	Year Ended March 31, 2023
		(in millions of dollars)	
Electric contracts	Regulatory assets (liabilities)	**$ 63**	$ 50
Gas contracts	Regulatory assets (liabilities)	**43**	88
Total changes in regulatory assets		**$ 106**	$ 138

Certain additional information about hedge accounting, disaggregated by risk type and hedge designation type, is provided in the tables below:

	Fair value hedges of foreign currency and interest rate risk		Cash flow hedges of foreign currency and interest rate risk	
	Year Ended March 31,		Year Ended March 31,	
	2024	2023	**2024**	2023
	(in millions of dollars)			
Statements of operations and comprehensive income				
Net gains (losses) in respect of				
Cash flow hedges	**n/a**	n/a	**$ 59**	$ (27)
Cost of hedging	**$ (3)**	$ (1)	**(8)**	(2)
Transferred to earnings in respect of				
Cash flow hedges	**n/a**	n/a	**(4)**	6
Cost of hedging	**1**	-	**1**	-
Statements of changes in equity				
Other equity reserves – cost of hedging balances	**(4)**	(2)	**(8)**	(1)

The following tables show the effects of hedge accounting on financial position and year-to-date performance for each type of hedge.

Fair value hedges of foreign currency and interest rate risk on recognized borrowings:

	March 31, 2024					
	(in millions of dollars)					
		Balance of fair value hedge adjustments in borrowings		**Change in value used for calculating ineffectiveness**		
Hedge type	**Hedging instrument notional**	**Continuing hedges**	**Discontinued hedges**	**Hedged item**	**Hedging instrument**	**Hedge ineffectiveness**
Foreign currency and interest rate risk on borrowings	**$ (1,142)**	**$ 104**	**$ (24)**	**$ (49)**	**$ 43**	**$ (6)**

	March 31, 2023					
	(in millions of dollars)					
		Balance of fair value hedge adjustments in borrowings		**Change in value used for calculating ineffectiveness**		
Hedge type	**Hedging instrument notional**	**Continuing hedges**	**Discontinued hedges**	**Hedged item**	**Hedging instrument**	**Hedge ineffectiveness**
Foreign currency and interest rate risk on borrowings	$ (1,404)	$ 193	$ (24)	$ 91	$ (86)	$ 5

Cash flow hedges of foreign currency and interest rate risk:

	March 31, 2024					
	(in millions of dollars)					
		Balance in cash flow hedge reserve		**Change in value used for calculating ineffectiveness**		
Hedge type	**Hedging instrument notional**	**Continuing hedges**	**Discontinued hedges**	**Hedged item**	**Hedging instrument**	**Hedge ineffectiveness**
Foreign currency and interest rate risk on borrowings	**$ (2,079)**	**$ 19**	**$ -**	**$ (55)**	**$ 51**	**$ (4)**

	March 31, 2023					
	(in millions of dollars)					
		Balance in cash flow hedge reserve		**Change in value used for calculating ineffectiveness**		
Hedge type	**Hedging instrument notional**	**Continuing hedges**	**Discontinued hedges**	**Hedged item**	**Hedging instrument**	**Hedge ineffectiveness**
Foreign currency and interest rate risk on borrowings	$ (1,327)	$ 36	$ -	$ 24	$ (25)	$ (1)

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price, interest rate, and foreign currency rate risk management. 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 Parent's Board of Directors ("Finance Committee"), 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 Company's credit exposure for all commodity derivative instruments and applicable payables and receivables, net of collateral, and instruments that are subject to master netting agreements, was a liability of $106 million and a liability of $138 million as of March 31, 2024 and 2023, respectively.

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, 2024 and 2023 was $88 million and $139 million, respectively. The Company had $25 million and $21 million collateral posted for these instruments as of March 31, 2024 and 2023, respectively. At March 31, 2024, 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 $6 million, $39 million, or $71 million, respectively. At March 31, 2023, 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 $21 million, $85 million, or $124 million, respectively. The counterparties had $16 million in collateral posted to the Company as of March 31, 2024.

Financing Transactions

The credit policy for financing transactions is managed by a central treasury department under policies approved by the Finance 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.

In relation to the Company's financial derivative instruments, the Company had $22 million and $162 million collateral posted for these instruments at March 31, 2024 and 2023, respectively. If the Company's credit rating were to be downgraded by one, two or three levels, it would not be required to post any additional collateral at March 31, 2024 and 2023.

11. 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, 2024 and 2023:

	March 31, 2024			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas contracts	**$ -**	**$ 4**	**$ -**	**$ 4**
Electric contracts	**-**	**42**	**-**	**42**
Interest rate swaps [(1)]	**-**	**81**	**-**	**81**
Sunrun investment	**-**	**-**	**133**	**133**
Financial investments				
Securities	**167**	**203**	**-**	**370**
Other	**-**	**-**	**56**	**56**
Total	**167**	**330**	**189**	**686**
Liabilities:				
Derivative instruments				
Gas contracts	**-**	**28**	**19**	**47**
Electric contracts	**-**	**104**	**1**	**105**
Foreign exchange forward contracts	**-**	**12**	**-**	**12**
Interest rate swaps [(1)]	**-**	**221**	**-**	**221**
Total	**-**	**365**	**20**	**385**
Net assets (liabilities)	**$ 167**	**$ (35)**	**$ 169**	**$ 301**

[(1)]Consists of cross-currency interest rate swaps and interest rate swaps.

	March 31, 2023			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 11	$ 1	$ 12
Electric contracts	-	65	1	66
Foreign exchange forward contract	-	10	-	10
Sunrun investment	-	-	131	131
Financial investments				
Securities	146	215	-	361
Other	-	-	47	47
Total	146	301	180	627
Liabilities:				
Derivative instruments				
Gas contracts	-	53	47	100
Electric contracts	-	113	3	116
Interest rate swaps [(1)]	-	269	-	269
Contingent consideration	-	-	23	23
Total	-	435	73	508
Net assets (liabilities)	$ 146	$ (134)	$ 107	$ 119

[(1)] Consists of cross-currency interest rate swaps and interest rate swaps.

Derivative Instruments

The Company's Level 2 fair value derivative instruments primarily consist of cross-currency, interest rate derivatives, and commodity swap contracts. The cross-currency and interest rate derivatives are valued by discounting all future cash flows by externally sourced market yield curves at the reporting date, taking into account the credit quality of both parties. The commodity swap contracts pricing inputs are obtained from NYMEX and the Intercontinental Exchange ("ICE"). 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 spread 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 OTC commodity option contracts and structured physical gas purchase contracts, which are valued based on internally-developed models. 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.

The Company did not have any Level 1 derivative instruments at either March 31, 2024 or March 31, 2023.

Sunrun Investment

The table below provides a reconciliation of the beginning and ending balance for the Company's investment in Sunrun, for which the Company elected the fair value option, which is classified as Level 3 in the fair value hierarchy. Changes in fair value are reported in Income from equity method investments in the accompanying statements of operations and comprehensive income.

	Year Ended March 31,	
	2024	2023
	(in millions of dollars)	
Beginning balance	**$ 131**	$ 139
Unrealized gains	**13**	2
Dividends	**(11)**	(10)
Ending balance	**$ 133**	$ 131

The fair value of the Company's investment in Sunrun is determined using a discounted cash flow, with Contractual Target internal rate of return ("IRR") being the significant unobservable input. The fair value measurement is driven by the contractual target IRR. The contractual nature of the distributions to the Class A and Class B Members and the Target IRR results in a low level of measurement uncertainty as it relates to the fair value measurement.

Contingent Consideration

The table below provides a reconciliation of the beginning and ending balance for the Company’s contingent consideration related to the acquisition of NGRD, which is classified as Level 3 in the fair value hierarchy. Changes in fair value are reported in Other interest, including affiliate interest in the accompanying statements of operations and comprehensive income.

	Year Ended March 31,	
	2024	2023
	(in millions of dollars)	
Beginning balance	**$ (23)**	$ (54)
Fair value adjustment	**-**	(5)
Addition	**-**	-
Payments	**23**	36
Ending balance	**$ -**	$ (23)

The fair value of the Contingent Consideration liability is determined using a discounted cash flow, with the estimated timing of project sales and the MWs associated with the sales being the significant unobservable inputs. The fair value measurement is driven by estimated volumes (MW) and timing of project sales over the next two years. During the year ended March 31, 2024, all remaining contingent consideration was paid out.

Financial Investments - Securities

Securities are included in Financial investments on the consolidated balance sheets and primarily include equity and 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,			
		2024	2023	**2024**	2023
		(in millions of dollars)			
Rabbi Trust municipal bonds	2057	**$ 209**	$ 225	**$ 203**	$ 217

The following table summarizes gains and losses recorded by the Company in relation to available for sale debt securities. No other than temporary impairments were recorded in earnings or other comprehensive income during the years ended March 31, 2024 and March 31, 2023.

	Location	March 31,	
		2024	2023
		(in millions of dollars)	
Gross realized gains	Other income, net	**$ 0**	$ 2
Gross realized losses	Other income, net	**(4)**	(5)
Net unrealized gains (losses) on debt securities	OCI	**3**	(10)

Equity Securities

The following table summarizes gains and losses recorded by the Company in relation to investments in equity securities.

	Location	March 31, 2024	March 31, 2023
		(in millions of dollars)	
Gross realized gains	Other income, net	$ **-**	$ -
Gross realized losses	Other income, net	**-**	-
Net unrealized gains (losses) on equity securities	Other income, net	**3**	(5)

Financial Investments – Other

The Company's other investments include corporate venture capital investments held by NGP and the Sunrun Grid Services investment held by NGV measured at fair value with changes in fair value recorded in the consolidated statements of operations and comprehensive income. These equity holdings comprise a series of small ownership interest in unquoted investments where prices or valuation inputs are unobservable, therefore the investments classified as Level 3.

12. 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 (deductions), 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, 2024 and 2023, the Company made contributions of approximately $8 million and $66 million, respectively, to the qualified pension plans. The Company expects to contribute $11 million to the qualified pension plans during the year ending March 31, 2025.

Benefit payments to pension plan participants for the years ended March 31, 2024 and 2023 were approximately $561 million and $594 million, respectively. Benefit payments for the years ended March 31, 2024 and 2023 included payments for annuity contract purchases that did not result in a settlement.

In addition, during the years ended March 31, 2024 and 2023, the Company agreed to purchase a group annuity contract that transferred approximately $647 million and $694 million, respectively, of pension obligations and related plan assets to an insurance company. These transactions resulted in settlement gains of $7 million and $66 million, in years ended March 31, 2024 and 2023, respectively. Settlement gains in the year ended March 31, 2024 were recorded to other income as the transaction related to non-regulated entities. Settlement gains in the year ended March 31, 2023 were deferred as a regulatory liability as that transaction related to regulated entities.

As described in Note 20, "*Sale of Narragansett*," the Company sold a subsidiary, including pension and PBOP plans related to that business. This sale resulted in a curtailment and settlement loss of approximately $52 million within the Company's employee benefit plans for the year ended March 31, 2023.

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, 2024 and 2023, the Company made contributions of $14 million and $10 million, respectively, to the PBOP plans. The Company expects to contribute $11 million to the PBOP plans during the year ending March 31, 2025.

Gross benefit payments to PBOP plan participants for the years ended March 31, 2024 and 2023 were approximately $197 million and $185 million, respectively.

Components of Net Periodic Benefit Costs

	Pension Plans		**PBOP Plans**	
	Year Ended March 31,		**Year Ended March 31,**	
	2024	2023	**2024**	2023
	(in millions of dollars)			
Service cost	**$ 96**	$ 112	**$ 36**	$ 47
Interest cost	**322**	306	**147**	136
Expected return on plan assets	**(460)**	(444)	**(201)**	(190)
Amortization of prior service cost, net	**6**	6	**-**	-
Amortization of net actuarial loss (gain)	**58**	44	**(98)**	(76)
Settlement charge (credit)	**(7)**	10	**-**	(24)
Asset transfer charge (credit)	**-**	55	**-**	(9)
Total cost (credit)	**$ 15**	$ 89	**$ (116)**	$ (116)

Asset transfer charge relates to the sale of Narragansett.

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, 2024 and 2023:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2024	2023	**2024**	2023
	(in millions of dollars)			
Net actuarial loss (gain)	**$ (51)**	$ 437	**$ (137)**	$ (82)
Reversal of net actuarial gain (loss) from settlements	**7**	(9)	**-**	23
Reversal of net actuarial (loss) due to curtailment	**-**	(40)	**-**	-
Prior service cost	**1**	9	**-**	-
Amortization of net actuarial (loss) gain	**(58)**	(43)	**98**	76
Amortization of prior service cost, net	**(6)**	(6)	**-**	-
Total	**$ (107)**	$ 348	**$ (39)**	$ 17
Change in regulatory assets or liabilities	**$ (78)**	$ 401	**$ (48)**	$ (7)
Change in AOCI	**(29)**	(53)	**9**	24
Total	**$ (107)**	$ 348	**$ (39)**	$ 17

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, 2024 and 2023:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2024	2023	**2024**	2023
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 324**	$ 426	**$ (1,006)**	$ (967)
Prior service cost	**29**	34	**-**	-
Total	**$ 353**	$ 460	**$ (1,006)**	$ (967)
Included in regulatory assets (liabilities)	**$ 328**	$ 406	**$ (890)**	$ (842)
Included in AOCI	**25**	54	**(116)**	(125)
Total	**$ 353**	$ 460	**$ (1,006)**	$ (967)

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	Years Ended March 31		Years Ended March 31	
	2024	2023	**2024**	2023
	(in millions of dollars)			
Change in benefit obligation:				
Benefit obligation as of the beginning of the year	**$ (7,013)**	$ (8,896)	**$ (3,129)**	**$ (3,730)**
Service cost	**(96)**	(112)	**(36)**	**(47)**
Interest cost on projected benefit obligation	**(322)**	(306)	**(147)**	**(136)**
Plan amendment	**(1)**	(9)	**-**	**-**
Net actuarial loss (gain)	**270**	1,068	**76**	**634**
Benefits paid	**561**	594	**197**	**185**
Employer group waiver plan subsidy received	**-**	-	**(33)**	**(35)**
Settlements	**472**	608	**-**	**-**
Curtailments	**-**	40	**-**	**-**
Benefit obligation as of the end of the year	**$ (6,129)**	$ (7,013)	**$ (3,072)**	**$ (3,129)**
Change in plan assets:				
Fair value of plan assets as of the beginning of the year	**7,464**	9,572	**3,224**	**3,794**
Actual return on plan assets	**240**	(985)	**262**	**(399)**
Company contributions	**33**	91	**27**	**14**
Benefits paid	**(561)**	(594)	**(197)**	**(185)**
Settlements	**(472)**	(620)	**-**	**-**
Fair value of plan assets as of the end of the year	**$ 6,704**	$ 7,464	**$ 3,316**	**$ 3,224**
Funded status	**$ 575**	$ 451	**$ 244**	**$ 95**

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, 2024. The aggregate ABO balances for the Pension Plans were $5.9 billion and $6.8 billion as of March 31, 2024 and 2023, respectively.

Amounts Recognized on the Accompanying Consolidated Balance Sheets

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2024	2023	**2024**	2023
	(in millions of dollars)			
Projected benefit obligation	**$ (6,129)**	$ (7,013)	**$ (3,072)**	$ (3,129)
Fair value of plan assets	**6,704**	7,464	**3,316**	3,224
Total	**$ 575**	$ 451	**$ 244**	$ 95
Non-current assets	**$ 841**	$ 739	**$ 597**	$ 524
Current liabilities	**(25)**	(24)	**(8)**	(10)
Non-current liabilities	**(241)**	(264)	**(345)**	(419)
Total	**$ 575**	$ 451	**$ 244**	$ 95

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

For the year ended March 31, 2023, the net actuarial loss for Pension was largely driven by asset losses due to returns that were less than expected as well as the increase in the cash balance interest crediting rate, offset by the increase in discount rate and slight changes to the withdrawal assumption resulting from the recent experience study. The net actuarial gains for the PBOP Plans were driven by the increase in discount rate and savings resulting from a new Medicare Advantage contract for PBOP, offset by asset losses and the slight withdrawal assumption changes.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2024 (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**
2025	$ 403	$ 170
2026	398	179
2027	411	184
2028	424	189
2029	430	193
2030-2034	2,234	1,002
Total	$ 4,300	$ 1,917

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2024	2023	**2024**	2023
Benefit Obligations:				
Discount rate	**5.15%**	4.85%	**5.15%**	4.85%
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	**4.80%**	5.00%	**N/A**	N/A
Net Periodic Benefit Costs:				
Discount rate	**4.85%-5.70%**	3.65% - 5.05%	**4.85%**	3.65% - 4.30%
Rate of compensation increase (non-union)	**4.30%**	4.30%	**N/A**	N/A
Rate of compensation increase (union)	**4.70%**	4.25%	**N/A**	N/A
Expected return on plan assets	**6.25% - 6.50%**	4.25% - 5.75%	**6.25% - 6.75%**	5.00% - 6.00%
Weighted-average interest crediting rate for cash balanced plans	**5.00%**	3.00%	**N/A**	N/A

For the year ended March 31, 2024, discount rate used for remeasuring the purchase of the group annuity contract was 5.70%.

For the year ended March 31, 2023, discount rates used for remeasuring the annual pension expense and obligation for the sale of Narragansett and the purchase of the group annuity contract were 4.30% and for the payouts of lump sums in excess of the threshold as prescribed in ASC 715 was 5.05%.

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. Specifically, the Company uses the AON AA Only Bond Universe Curve along with 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,	
	2024	2023
Health care cost trend rate assumed for next year		
Pre 65	**6.20%**	6.40%
Post 65	**5.10%**	5.20%
Prescription	**8.00%**	7.10%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre 65	**2031**	2031+
Post 65	**2031**	2031+
Prescription	**2033**	2031+

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

The RPC has established and reviews at least annually the Investment Policy Statement ("IPS") which sets forth the guidelines for how plan assets are to be invested. The IPS contains a strategic asset allocation for each plan, which is intended to meet the objectives of the Plans by diversifying their funds across asset classes, investment styles, and fund managers. An asset/liability study 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 2024 reflects the results of such a pension study conducted and implemented in fiscal year 2024. As a result of that asset/liability analysis, the asset mix for the Pension Plans were changed to further reduce investment risk given the increased funded status of the plans and to better hedge the respective plan liabilities. The Non-Union PBOP Plan asset liability study was conducted in fiscal year 2024. As a result of that study, the RPC approved changes to the KeySpan and Niagara Mohawk Non-Union PBOP asset allocation effective in fiscal year 2024. The last Union PBOP study was conducted in fiscal year 2023. As a result of that asset/liability analysis, the asset mix was changed to further reduce investment risk given the increased funded status of the Plans and to better hedge the respective plan liabilities. Those change took effect during fiscal year 2023.

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 securities, other asset classes are utilized to further diversify the investments. These asset classes include private equity, real estate, and diversified alternatives. The objective of these other investments is enhancing long-term returns while improving portfolio diversification. For the PBOP Plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after-tax returns consistent with the broad asset class parameters established by the asset/liability study. Investment risk and return are reviewed by the plan investment advisors, National Grid management, and the RPC on a regular basis. The assets of the Plans have no significant concentration of risk in one country (other than the United States), industry, or entity.

The target asset allocations for the benefit plans as of March 31, 2024 and 2023 are as follows:

	National Grid Pension Plans		**Union PBOP Plans**		**Non-Union PBOP Plans**	
	March 31,		**March 31,**		**March 31,**	
	2024	2023	**2024**	2023	**2024**	2023
Equity	**12%**	22%	**15%**	15%	**67%**	70%
Diversified alternatives	**4%**	7%	**5%**	5%	**0%**	0%
Fixed income securities	**61%**	61%	**80%**	80%	**33%**	30%
Private equity	**12%**	5%	**0%**	0%	**0%**	0%
Real estate	**5%**	3%	**0%**	0%	**0%**	0%
Infrastructure	**6%**	2%	**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, 2024				
	Level 1	**Level 2**	**Level 3**	**Not categorized**	**Total**
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	**$ 132**	**$ -**	**$ -**	**$ 755**	**$ 887**
Diversified alternatives	**67**	**-**	**-**	**262**	**329**
Corporate bonds	**-**	**2,543**	**-**	**469**	**3,012**
Government securities	**5**	**631**	**-**	**560**	**1,196**
Private equity	**-**	**-**	**-**	**781**	**781**
Real estate	**-**	**-**	**-**	**298**	**298**
Infrastructure	**-**	**-**	**-**	**371**	**371**
Total assets	**$ 204**	**$ 3,174**	**$ -**	**$ 3,496**	**$ 6,874**
Pending Transactions					**(170)**
Total net assets					**$ 6,704**
PBOP assets:					
Investments					
Equity	**$ 45**	**$ -**	**$ -**	**$ 661**	**$ 706**
Diversified alternatives	**117**	**-**	**-**	**11**	**128**
Corporate bonds	**-**	**1,709**	**-**	**52**	**1,761**
Government securities	**61**	**425**	**-**	**1**	**487**
Insurance contracts	**-**	**-**	**-**	**202**	**202**
Total assets	**$ 223**	**$ 2,134**	**$ -**	**$ 927**	**$ 3,284**
Pending Transactions					**32**
Total net assets					**$ 3,316**

	March 31, 2023				
	Level 1	**Level 2**	**Level 3**	**Not categorized**	**Total**
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	$ 191	$ -	$ -	$ 886	$ 1,077
Diversified alternatives	105	-	-	351	456
Corporate bonds	-	2,703	-	605	3,308
Government securities	10	633	-	629	1,272
Private equity	-	-	-	772	772
Real estate	-	-	-	369	369
Infrastructure	-	-	-	326	326
Total assets	$ 306	$ 3,336	$ -	$ 3,938	$ 7,580
Pending Transactions					(116)
Total net assets					$ 7,464
PBOP assets:					
Investments					
Equity	$ 90	$ -	$ -	$ 630	$ 720
Diversified alternatives	124	-	-	12	136
Corporate bonds	-	1,650	-	-	1,650
Government securities	75	429	-	1	505
Private Equity	-	-	-	-	-
Insurance contracts	-	-	-	181	181
Total assets	$ 289	$ 2,079	$ -	$ 824	$ 3,192
Pending Transactions					32
Total net assets					$ 3,224

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 U.S. agency securities, U.S. treasury securities, state and local municipal bonds, as well as a U.S. Treasury exchange-traded fund. The Plans hold 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 included in this category as a tool to manage interest rate risk.

Private equity: Private equity consists of limited partnership 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 partnership 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 **c**ategorized: 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: These 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, 2024 and 2023, the Company recognized an expense in the accompanying consolidated statements of operations and comprehensive income of $120 million and $92 million, respectively.

13. CAPITALIZATION

Total for the Company at March 31, 2024 and 2023 is as follows:

			March 31,	
			2024	2023
			(in millions of dollars)	
Common shareholders' equity			**$ 23,571**	$ 22,339
Non-controlling interest			**64**	62
Long-term debt:	Interest Rate	Maturity Date		
Brooklyn Union Unsecured Notes:				
Senior Note	3.41%	March 10, 2026	**500**	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**	-
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
Brooklyn Union Notes			**3,850**	3,450
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	4.49%	February 15, 2042	**500**	500
Senior Note	4.63%	March 15, 2042	**25**	25
Senior Note	6.12%	July 20, 2053	**400**	-
Boston Gas Medium-Term Notes:				
MTN Series 1995 C	6.95%	December 1, 2023	**-**	10
MTN Series 1994 B	6.98%	January 15, 2024	**-**	6
MTN Series 1995 C	6.95%	December 1, 2024	**5**	5

MTN Series 1995 C	7.25%	October 1, 2025	**20**	20
MTN Series 1995 C	7.25%	October 1, 2025	**5**	5
Boston Gas Notes			**2,505**	2,121
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	3.51%	October 1, 2024	**500**	500
Senior Note	4.28%	December 15, 2028	**500**	500
Senior Note	1.96%	June 27, 2030	**600**	600
Senior Note	2.76%	January 10, 2032	**400**	400
Senior Note	5.29%	January 17, 2034	**500**	-
Senior Note	4.28%	October 1, 2034	**400**	400
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**	-
Niagara Mohawk Notes			**5,000**	3,800
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**	-
Massachusetts Electric Notes:			**2,200**	1,800
New England Power Unsecured Notes:				
Senior Notes	3.80%	December 5, 2047	**400**	400
Senior Notes	2.81%	October 6, 2050	**400**	400
Senior Notes	5.94%	November 25, 2052	**300**	300
New England Power Notes:			**1,100**	1,100
Total Notes Payable			**17,462**	15,078
European Medium Term Notes	Variable	June 2024 – September 2033	**3,349**	2,832
Export Credit Agreements	Variable	October 2025 – March 2029	**1,225**	1,180
First Mortgage Bonds	6.90% - 7.38%	October 2025 – April 2028	**50**	50

State Authority Financing Bonds	3.29% - 3.48%	December 2025 – July 2029	**355**	424
State Authority Financing Bonds	Variable	December 2027 – August 2042	**117**	117
Term Loans	Variable	December 2024	**-**	200
Total debt			**22,558**	19,881
Unamortized debt discount			**(4)**	(48)
Unamortized debt issuance costs			**(111)**	(75)
Current portion of long-term debt			**(1,604)**	(871)
Total long-term debt			**20,839**	18,887
Total capitalization			**$ 44,474**	$ 41,288

The aggregate maturities of long-term debt for the years subsequent to March 31, 2024, are as follows:

(in millions of dollars) March 31,	Maturities of Long-Term Debt
2025	$ 1,604
2026	1,706
2027	1,209
2028	1,852
2029	1,333
Thereafter	14,854
Total	$ 22,558

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, 2024, and 2023, the Company was in compliance with all such covenants.

Significant Debt Facilities

European Medium-Term Note Program

At March 31, 2024, the Company had a Euro Medium Term Note program (the "Program") under which it is able to issue debt instruments ("Instruments") up to a total of the equivalent of €8 billion Euros. Instruments issued under the Program are admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and is renewed annually, with the latest renewal of the Program having occurred in August 2023. If the Program was not renewed, it would have precluded the issuance of new notes under this Program, but it would not impact the outstanding debt balances and their maturity dates. Instruments carry certain affirmative and negative covenants, including a restriction on the Company's ability to mortgage, pledge, charge, or otherwise encumber its assets in order to secure, guarantee, or indemnify other listed or quoted debt obligations, as well as cross-acceleration in the event of breach by the Company or its principal subsidiaries of other listed or quoted debt obligations. At March 31, 2024 and 2023, the Company was in compliance with all covenants. At March 31, 2024 and 2023, $3.3 billion and $2.8 billion of these notes were issued and outstanding, respectively.

Export Credit Agreements

The Company has drawn $1,225 million and $1,180 million of Export Credit Agency-backed (ECA) Facility Agreements as of March 31, 2024 and 2023, respectively. The Company has procured this financing in relation to Parent's share of investment in the North Sea Link interconnector, Interconnexion France-Angleterre 2 interconnector and Viking Interconnector projects.

First Mortgage Bonds ("FMB")

The assets of Boston Gas are subject to liens and other charges and are provided as collateral over borrowings of non-callable FMB of $50 million at March 31, 2024 and 2023. These FMB indentures include, among other provisions, limitations on the issuance of long-term debt.

State Authority Financing Bonds

At March 31, 2024, the Company had outstanding $471 million of State Authority Financing Bonds, of which $420 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 $355 million of tax-exempt revenue bonds issued by the NYSERDA in a fixed rate interest mode ranging from 3.29% to 3.48%.

Genco had $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028, issued through NYSERDA. The interest rate on the various variable rate series ranged from 2.92% to 5.00% during the year ended March 31, 2024, and 0.38% to 4.75% during the year ended March 31, 2023. Genco also has outstanding $25 million of variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027 issued through NYSERDA. The interest rate on the various variable rate series ranged from 2.45% to 4.85% during the year ended March 31, 2024, and 0.55% to 4.75% during the year ended March 31, 2023.

Nantucket had $51 million of Electric Revenue Bonds in tax exempt commercial paper mode, with maturity dates ranging from March 2039 to August 2042. The Electric Revenue Bonds were issued by the MDFA in connection with Nantucket's financing of its first and second underground and submarine cable projects.

Term Loans

In December 2022, Boston Gas entered into a $200 million Term loan at a variable interest rate with a maturity date of December 1, 2023, with an extension option of up to additional 13 months. On July 27, 2023, the Term Loan was fully repaid.

Intercompany Notes Payable

NGNA's intercompany debt is in the form of intercompany loans from the Parent and other non-consolidated affiliated entities obtained to fund the acquisition of various entities. The intercompany loans are paid back by NGNA from the dividends it receives from NGUSA. There were no intercompany loans payable outstanding at March 31, 2024 and March 31, 2023.

Standby Bond Purchase Agreement

Nantucket has a Standby Bond Purchase Agreement, which expires on May 31, 2028. This agreement provides liquidity support for the $51 million long-term bonds in tax-exempt commercial paper mode, as noted under the State Authority Financing Bonds section above. The Company has classified the debt as long-term due to its intent and ability to refinance the debt on a long-term basis in the event of a failure to remarket the bonds.

Committed Facility Agreements

At March 31, 2024, the Company, NGUSA, and the Parent had committed revolving credit facilities of approximately $6.7 billion, all of which have expiry dates beyond March 31, 2026, with two one year extensions. At March 31, 2024 these facilities have not been drawn against.

The facilities are comprised of two distinct and separate single currency tranches, namely a GBP £2.1 billion and a USD $4.0 billion tranche. The Company, NGUSA, 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 U.S. subsidiaries of the Company to $35 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which the Company is obliged to meet. At March 31, 2024 and 2023, the Company, NGUSA, and the Parent were in compliance with all covenants.

Commercial Paper and Revolving Credit Agreements

At March 31, 2024, the Company had two commercial paper programs approximately totaling $8.3 billion; a $4 billion U.S. commercial paper program and a €4 billion Euro commercial paper program. In support of these programs, the Company was a named borrower under the Parent’s credit facilities with $6.7 billion available to the Company. These facilities support both the Parent’s and the Company’s commercial paper programs for ongoing working capital needs. At March 31, 2024, there were $687 million of borrowings outstanding on the U.S. commercial paper program and $1,136 million outstanding on the Euro commercial paper program. At March 31, 2023, there were $61 million of borrowing outstanding on the U.S. commercial paper program and $596 million outstanding on the Euro commercial paper program.

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, 2022 and expires on October 14, 2024. Niagara Mohawk had no external short-term debt as of March 31, 2024 and 2023.

On April 1, 2021, Niagara Mohawk petitioned the NYPSC for authorization to issue, from time to time, through June 30, 2024, new long-term debt in an amount not to exceed $3 billion. On September 13, 2021, the NYPSC authorized Niagara Mohawk to issue up to $2.3 billion of new long-term debt securities. The authorized securities will enable Niagara Mohawk to fund the construction of utility plant, refinance maturing and/or redeemed issues of debt, redemption of preferred stock, refinance callable debt, refinance short-term debt with long-term debt, finance the capital needs of Niagara Mohawk, and meet other general corporate purposes through June 30, 2024, subject to the terms of the order. In addition, 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.

Brooklyn Union

On June 17, 2022, 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, 2025. Under this authorization, on August 5, 2022, the Company issued $400 million 10-year and $400 million 5-year unsecured long-term debt with fixed rates of 4.87% and 4.63%, respectively. On September 15, 2023, Brooklyn Union issued $400 million 10-year long-term debt with a fixed rate of 6.39%.

KeySpan Gas East

On June 17, 2022, the NYPSC authorized KeySpan Gas East to issue up to $890 million 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, 2025.

Under the authorization, on March 6, 2023, the Company issued $500 million 10-year unsecured long-term debt with a fixed rate of 5.99%.

Boston Gas

On July 20, 2023, Boston Gas issued $400 million of unsecured senior long-term debt at a fixed rate of 6.12% with a maturity date of July 20, 2053.

Boston Gas has authority to issue long-term debt securities through November 2024 of up to $1.5 billion and has issued $1.0 billion so far. On April 3, 2024, Boston Gas filed a motion to extend the financing authority for one year until November 2025 so that it may use the remaining $500 million and requested an increase in the maximum interest rate from 7 percent to 8 percent. The DPU issued a procedural schedule with discovery concluding by May 3, 2024, and a request for an evidentiary hearing and/or briefing by May 7, 2024, which would allow for an order by June 30, 2024, as requested by Boston Gas. Initial briefs were filed on May 29, 2024, by the Boston Gas and Attorney General. The Attorney General does not object to Boston Gas's request for extension of the financing term but does not support increasing the interest rate to 8 percent. Boston Gas filed its reply brief on June 4, 2024, stating that the increase of the maximum interest rate to 8 percent is appropriate given the recent market trends, along with a motion to strike a statement the Attorney General made for the first time on brief unsupported by the record. Comments on the Boston Gas's motion are due June 10, 2024. The Attorney General did not file a substantive reply brief.

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, 2024. Massachusetts Electric had no external short-term debt as of March 31, 2024 and 2023.

On August 31, 2020, 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, 2023. On July 17, 2023, Massachusetts Electric received approval from the DPU to extend the issue up to $1.1 billion of long-term debt in one or more transactions through August 31, 2024. In November 2020, Massachusetts Electric issued $500 million of unsecured long-term debt at 1.73% with a maturity date of November 24, 2030. On February 26, 2024, Massachusetts Electric issued $400 million of unsecured long-term debt at 5.87% with a maturity date of February 26, 2054, resulting in $200 million of remaining authorization.

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, 2022 and expires on October 14, 2024. NEP had no short-term debt outstanding as of March 31, 2024 and 2023.

On May 23, 2017, NEP had received all required approvals from the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission and Vermont Public Service Board authorizing NEP to issue up to $800 million of long-term debt in one or more transactions through May 23, 2020. On November 30, 2017, NEP issued $400 million of unsecured senior long-term debt with a maturity date of December 5, 2047.

On August 31, 2020, NEP received additional approvals from the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission and Vermont Public Service Board authorizing NEP to issue up to $1.1 billion of long-term debt in one or more transactions through August 31, 2023. On October 6, 2020, NEP issued $400 million of unsecured senior long-term debt with a maturity date of October 6, 2050. On November 25, 2022, NEP issued $300 million of unsecured senior long-term debt with a maturity date of November 25, 2052.

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, 2022 and expires on October 14, 2024. Genco had no short-term debt outstanding to third-parties as of March 31, 2024 or 2023.

Nantucket

Nantucket has regulatory approval from the FERC to issue up to $15 million of short-term debt. The authorization was renewed with an effective date of October 15, 2022 and expires on October 14, 2024. Nantucket had no external short-term debt as of March 31, 2024 and 2023.

14. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2024	2023
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ 5**	$ 201
State	**(15)**	54
Total current tax expense (benefit)	**(10)**	255
Deferred tax expense (benefit):		
Federal	**152**	238
State	**92**	203
Total deferred tax expense (benefit)	**244**	441
Amortized investment tax credits [1]	**(3)**	(3)
Total deferred tax expense (benefit)	**241**	438
Total income tax expense (benefit)	**$ 231**	$ 693

[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, 2024 and 2023 are 16.2% and 27.2%, 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,	
	2024	2023
	(in millions of dollars)	
Computed tax	**$ 300**	$ 536
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**61**	204
Goodwill – Narragansett Sale	**-**	114
Amortization of regulatory tax liability, net	**(117)**	(137)
R&D Credit, net of reserves	**(3)**	(12)
Other	**(10)**	(12)
Total changes	**(69)**	157
Total income tax expense	**$ 231**	$ 693

The Company files a consolidated federal income tax return and Massachusetts and New York unitary state income tax returns. The Company has joint and several liability for any potential assessments against the consolidated group.

Inflation Reduction Act

On August 16, 2022, President Biden signed into law the Inflation Reduction Act ("IRA"), which may impact how the U.S. taxes certain large corporations. The IRA imposes a 15% corporate alternative minimum tax ("CAMT") on the "adjusted financial statement income" of certain large corporations for tax years beginning after December 31, 2022. National Grid is subject to the new CAMT on its federal income tax return for the tax year ending 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.

In April 2023, the IRS released Revenue Procedure 2023-15, which provides a safe harbor method of accounting that taxpayers may use to determine whether certain expenditures to maintain, repair, replace, or improve natural gas transmission and distribution property must be capitalized as improvements by the taxpayer or currently deducted for federal income tax purposes. The Company does not expect the impact to be material to its results of operations, financial position, or cash flows.

Deferred Tax Components

	March 31,	
	2024	2023
	(in millions of dollars)	
Deferred tax assets:		
Allowance for bad debts	**$ 185**	$ 170
Environmental remediation costs	**907**	700
Net operating losses	**211**	25
Postretirement benefits	**184**	214
Regulatory liabilities	**1,669**	1,594
Reserves not currently deducted	**308**	262
Corporate alternative minimum tax credit	**108**	-
Other items	**380**	511
Total deferred tax assets	**3,952**	3,476
Deferred tax liabilities:		
Property related differences	**7,046**	6,617
Regulatory assets	**1,985**	1,592
Other items	**451**	392
Total deferred tax liabilities	**9,482**	8,601
Net deferred income tax liabilities	**5,530**	5,125
Deferred investment tax credits	**40**	43
Deferred income tax liabilities, net	**$ 5,570**	$ 5,168

The deferred tax assets associated with the tax credit carryforwards are presented net with the deferred tax liability in the Company's consolidated balance sheets.

Net Operating Losses

The amounts and expiration dates of the Company's net operating losses carryforward as of March 31, 2024 are as follows:

	Gross Carryforward Amount *(in millions of dollars)*	Expiration Period
Federal	711	Indefinite
Massachusetts	426	2044
New York	1,843 [2]	2035 - 2044
New York City	366 [2]	2035 - 2044

[2] 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.

Tax Years Subject to Examination

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

Jurisdiction	Tax Years
Federal	March 31, 2021
Massachusetts	March 31, 2013
New York	March 31, 2010
New York City	March 31, 2010

Uncertain Tax Positions

As of March 31, 2024 and 2023, the Company's unrecognized tax benefits totaled $359 million and $373 million, respectively of which $74 million and $75 million, respectively, would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in other non-current liabilities in the accompanying consolidated balance sheets.

The following table presents changes to the Company's unrecognized tax benefits:

	Year Ended March 31,	
	2024	2023
	(in millions of dollars)	
Beginning balance	**$ 373**	$ 421
Gross increases – tax positions in prior periods	**55**	25
Gross decreases – tax positions in prior periods	**(25)**	(128)
Gross increases - current period tax positions	**26**	101
Gross decreases - current period tax positions	**(5)**	(46)
Reductions due to lapse of statute of limitations	**(65)**	-
Ending balance	**$ 359**	$ 373

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 income. As of March 31, 2024 and 2023, the Company has accrued for interest related to unrecognized tax benefits of $27 million and $16 million, respectively. During the years ended March 31, 2024 and 2023, the Company recorded interest expense of $11 million and interest income of $8 million, respectively. No tax penalties were recognized during the years ended March 31, 2024 and 2023.

It is reasonably possible that other events will occur during the next twelve months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any other additional increases or decreases would be material to its results of operations, financial position, or cash flows.

15. 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, including the U.S. Environmental Protection Agency ("EPA"), the New York State Department of Environmental Conservation ("DEC"), the New York City Department of Environmental Protection, and the Nassau and Suffolk County Departments of Health.

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 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. 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 certain of Genco's Long Island based electric generating facilities. The total cost of these improvements was approximately $106 million, all of which have been placed in service as of the date of this report; a mechanism for recovery from LIPA of these investments has been established. Additional NOx reduction system installation has been completed at the Glenwood Unit 2 gas turbine system, E.F. Barrett and East Hampton gas turbine units. A mechanism for recovery from LIPA of these investments has been established. Genco 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 to aquatic organisms. Final permits have been issued and work is completed for Port Jefferson and Northport. 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"). The date when the final permit will be issued is currently unknown. Costs associated with these capital improvements 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, 2024 and 2023, the Company's total reserve for estimated MGP-related environmental matters is $3.3 billion and $2.5 billion, respectively. These costs are expected to be incurred over approximately 47 years, and these undiscounted amounts have been recorded as estimated liabilities on the consolidated balance sheets. The Company had a current portion of environmental remediation costs of $255 million and $168 million included in other current liabilities on the consolidated balance sheets at March 31, 2024 and 2023, respectively. 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 $3.2 billion and $2.5 billion on the consolidated balance sheets at March 31, 2024 and 2023, respectively. Expenditures incurred for the years ended March 31, 2024 and 2023 were approximately $118 million and $110 million, respectively. 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.

During the year ended March 31, 2024, the Company received new information from environmental regulators concerning the design and remediation work required at several sites. Through ongoing technical scope discussions with the regulators concerning their expectations for these sites, the Company revised the anticipated scope of remediation work to be performed. Accordingly, the Company recorded an increase to the environmental obligation for these sites of $834 million, reflecting estimates prepared by third-party engineers for the revised scope of remediation work to be performed. After recording an offsetting increase in regulatory assets relating to environmental remediation, there was no impact to the net assets of the Company. Discussions with regulators will continue and final selection of technologies and remedial actions required will be made based on the results of field studies. Depending on the final selection of technologies and remedial actions required, there could be a material change to the reserve, which would have a corresponding offsetting change in regulatory assets due to regulatory recovery of environmental remediation costs.

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.

16. 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, 2024 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	**Energy Purchases**	**Capital Commitments**
2025	$ 1,562	$ 498
2026	1,233	252
2027	1,334	320
2028	1,181	261
2029	1,087	241
Thereafter	11,428	134
Total	$ 17,825	$ 1,706

Long-term Contracts for Renewable Energy

Offshore Wind Energy Procurement

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 MW. 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. Based on the terms of the contracts, the commercial operations date for the first wind farm was initially expected to be in January 2022, with the second wind farm anticipated in May 2022. On October 21, 2021, the DPU approved two amendments to the PPAs for both wind farms, which extend the critical milestone dates by twenty-four months, including the commercial operations dates. On November 7, 2023, Vineyard Wind notified the MA EDCs of their intent to utilize three (3) of the available six month critical milestone extensions in the Facility 1 PPA, and two (2) of the available six month critical milestone extensions in the Facility 2 PPA. As such, the new guaranteed commercial operations dates are July 15, 2025 for the first wind farm and May 31, 2025 for the second wind farm.

Offshore Wind Energy Procurement: Round 2

On January 10, 2020, the Massachusetts Electric Companies entered into two separate 20-year PPAs with Mayflower Wind Energy LLC ("Mayflower Wind") for the purchase of 45.41% of the electricity and renewable energy credits generated by two offshore wind farms proposed by Mayflower Wind, with the first wind farm having a capacity of up to 408 MWs and the second having a capacity of up to 396 MWs. The contracts with Mayflower Wind were entered into pursuant to Section 83C of the Green Communities Act. Based on the terms of the contracts, the commercial operations date for the first wind farm was initially expected to be in September 2025, with the second wind farm anticipated in December 2025. These contracts were filed with the DPU on February 10, 2020. On November 5, 2020, 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. The AG filed a motion for reconsideration on November 25, 2020, in which the AG asked the DPU for additional information regarding the DPU's approval of 2.75% remuneration on the annual payments made. The AG's motion was denied on June 23, 2021. On July 9, 2021, the decision became final and unappealable, and regulatory approval was achieved. On May 25, 2022, the Massachusetts Electric Companies filed an amendment to the PPAs for the DPU's review and approval. The amendment extends the critical milestone dates by approximately eighteen months, including the commercial operations dates. On December 30, 2022, the DPU issued a stamp approval, approving the proposed amended contract.

Offshore Wind Energy Procurement: Round 3

On April 8, 2022, the Massachusetts Electric Companies entered into a 20-year PPA with Commonwealth Wind LLC ("Commonwealth Wind") for the purchase of 43.87% of the electricity and renewable energy credits generated by a proposed offshore wind farm with a nameplate capacity of 1,232 MWs. On April 15, 2022, the Massachusetts Electric Companies entered into a 20-year PPA with Mayflower Wind for the purchase of 38.003% of the electricity and renewable energy credits generated by a proposed offshore wind farm with a nameplate capacity of 480 MWs. Both PPAs were filed with the DPU for its review and approval on May 25, 2022. These contracts were entered into pursuant to Section 83C of the Green Communities Act. The Commonwealth Wind project has a commercial operations date of November 2027, and the Mayflower Wind project has a commercial operations date of March 2028.

On October 20, 2022, Avangrid, the developer of the Commonwealth Wind project, requested a one-month delay in the DPU's review of the Commonwealth Wind contract to allow time for Avangrid to renegotiate the contracted electricity price. Avangrid cited the war in Ukraine, inflation, supply chain issues, and rising interest rates as factors in its decision to request what it describes as a modest increase in price. Mayflower Wind supported Avangrid's motion for a delay and indicated that it wanted to renegotiate its own contracted electricity price. On November 4, 2022, the DPU issued an order rejecting Avangrid's request for a delay. On November 7, 2022, Mayflower Wind filed a response to the DPU it which it withdrew its support for Avangrid's motion to delay the proceedings and stated that it intends to move forward with the existing PPAs. On November 14, 2022, Avangrid filed its response to the DPU order, stating that "absent the relief that Commonwealth Wind has previously requested, the Department should not dismiss the [contract review] proceedings." On December 30, 2022, the DPU issued an order approving both proposed contracts. On January 19th, 2023, Commonwealth wind filed a Petition to Appeal. Also on January 19th, 2023, Mayflower Wind filed a motion petitioning for full participant status in the proceeding, and a request for an extension of the appeal period. On March 14, 2023, the DPU issued an order denying both requests.

Offshore Wind Energy Procurement: Termination of Round 2 and 3

As noted above, both Commonwealth Wind and SouthCoast Wind (formerly Mayflower Wind) 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.

On July 13, 2023, the Massachusetts Electric Companies filed a First Amendment to the Commonwealth Wind Power Purchase Agreement which allows for Termination and Release of the Agreement. The primary terms of the amendment include a termination payment, payable to each distribution company, which will be returned to their customers; Commonwealth Wind is additionally required to file any necessary motions in order to withdraw their appeal of the DPU's approval of the PPA with the MA Supreme Judicial Court. On August 23, 2023, the DPU issued its Stamp Approval of the Commonwealth Amendment. The contract was terminated as per the Effective Date of October 2, 2023.

On August 29, 2023, the Massachusetts Electric Companies filed Second Amendments to both phases of the SouthCoast Wind Round 2 and 3 Power Purchase Agreements, which allow for Termination and Release of the Agreements. The primary terms of the amendments include termination payments, payable to each distribution company, which will be returned to their customers. On September 29, 2023, the DPU issued its Stamp Approval of the SouthCoast Amendments. The contract was terminated as per the Effective Date of October 23, 2023.

As of November 1, 2023, the Massachusetts Electric Companies has received all termination payments, totaling approximately $49 million. These funds are currently being returned to customers through distribution rates, effective March 1, 2024.

Clean Energy Procurement

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 first agreement is a 20-year PPA with H.Q. Energy Services Inc., ("H.Q. Energy") for the purchase of approximately 498 MWhs 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"). This agreement was assigned to NECEC by Central Maine Power Company, with the consent of the Massachusetts Electric Companies. The TSA provides for the transmission of the electricity supplied by H.Q. Energy on a proposed new transmission line that will run from the United States border to Lewiston, Maine, where it will interconnect with the ISO-NE system. Both the TSA with NECEC and the PPA with H.Q. Energy are contingent on the successful development and construction of the underlying transmission line by NECEC. The anticipated commercial operations date of the transmission line is in August 2024, based on the contractual terms. 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. NextEra Energy Resources, LLC filed an appeal of the DPU's approval of the PPA with H.Q. Energy on July 12, 2019. On September 3, 2020, the Massachusetts Supreme Judicial Court upheld the DPU's approval. On November 2, 2021, the citizens of Maine passed a referendum which rejected the construction of the NECEC transmission line. NECEC has halted construction at the request of Maine's Governor while appeals are ongoing.

In August 2022, the Maine Supreme Judicial Court ruled that the 2021 ballot initiative is unconstitutional, if NECEC can prove they have completed enough of the project to have earned “vested rights” in continuing with the project. This case was remanded to the Business and Consumer Court; on April 20, 2023, a jury unanimously ruled in favor of Central Maine Power. While this ruling is still subject to appeal, CMP is legally permitted to resume work on the project as of this ruling.

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, 2024, 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)	$ 175	Revolving
Commodity Guarantees and Other	(ii)	153	July 2025 – August 2042
Letters of Credit	(iii)	765	April 2024 – March 2025
Grid NY, LLC	(iv)	48	None
Environmental Remediation Trust	(v)	74	2037
		$ 1,215	

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 has guaranteed commodity-related, operational payments for certain subsidiaries and in support of letter of credit facility for NGRD development projects. These guarantees are provided to third-parties to facilitate physical and financial transactions supporting the purchase and transportation of natural gas, oil, and other petroleum products for gas and electric production and financing activities. The guarantees cover actual transactions by these subsidiaries that are still outstanding as of March 31, 2024.

(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 Company has entered into a Parent Guaranty (the “Guaranty”) dated November 14, 2014 for the benefit of NY Transco LLC. The Company, through a wholly owned subsidiary, Grid NY LLC, has an equity investment in NY Transco LLC, which is an independent transmission company that competes for and builds new bulk power transmission facilities in New York. The Guaranty irrevocably and unconditionally guarantees all of Grid NY LLC’s payment obligations under the New York Transco Limited Liability Company Agreement (“NY Transco LLC Agreement”) dated November 14, 2014 entered into by and among Consolidated Edison Transmission, LLC, Grid NY LLC, Iberdrola USA Networks, NY Transco, LLC and Central Hudson Electric Transmission LLC. Grid NY LLC’s payment obligations relate to, but are not limited to, funding project development, obtaining initial regulatory approvals and making capital contributions as set forth in the NY Transco LLC Agreement.

(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 13 year term are approximately $74 million.

As of March 31, 2023, the Company and the Parent had jointly guaranteed certain payment obligations of a former subsidiary (KeySpan Ravenswood LLC) associated with a merchant electric generating facility leased by that subsidiary under a sale/leaseback arrangement. The subsidiary and the facility were sold in 2008. However, the original lease remained in place and the Company and the Parent were obligated to continue making the required payments under the lease through 2040. The cash consideration from the buyer of the facility included the remaining lease payments on a net present value basis. At March 31, 2023, the Company's obligation related to the lease was $35 million and was reflected in other non-current liabilities on the consolidated balance sheets. In the event the Company and the Parent default on the lease payment obligations, and that causes the buyer to lose beneficial use of the leased facility, the buyer was entitled to the unamortized value of the leased facility purchase price ("Ravenswood Guarantee"). At March 31, 2023, the unamortized value of the leased facility purchase price was $185 million.

On August 10, 2023, the Company finalized an agreement with the buyer in which the Company made a net $25 million payment to the buyer, which resulted in the full release of the Company and the Parent from all obligations related to the Ravenswood Guarantee, including the lease obligation. At August 10, 2023, the unamortized value of leased facility purchase price was $182 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.

Federal and Regulatory Investigations into Allegations of Fraud and Bribery

On June 17, 2021, five former employees of National Grid USA Service Company, Inc. in the downstate New York facilities department were arrested on federal charges alleging fraud and bribery. The five former employees subsequently pleaded guilty to the charges, pursuant to plea agreements, and have been sentenced. NGUSA was deemed a victim of the crimes. On June 23, 2021, based on the US Attorney's announcement, the NYPSC issued an order commencing a proceeding to examine certain programs and related capital and O&M expenditures of NGUSA and the New York Gas companies. The DPU, NYPSC, and the Rhode Island Public Utilities Commission have issued requests for information related to the alleged criminal conduct. The DPU has indicated that it will open an investigation into this matter after the conclusion of the NYPSC's investigation. The Company has fully cooperated with the NYPSC's inquiries regarding the alleged misconduct. The Company does not expect this matter will have a materially adverse effect on its results of operations, financial position, or cash flows.

Energy Efficiency Programs Investigation

National Grid has concluded its internal investigation in New York but continues to participate in regulatory proceedings in Massachusetts and Rhode Island regarding certain conduct associated with energy efficiency programs at the Company's affiliates. At this time, it is not possible to predict the outcome of the investigation or determine the amount, if any, of any liabilities that may be incurred in connection with it by the Company or its affiliates. However, the Company does not expect this matter will have a material adverse effect on its results of operations, financial position or cash flows.

Nassau County Special District Tax Settlement

In August 2021, KeySpan Gas East Corporation received approval from the Nassau County Legislature in Resolution No. 116-2021 whereby the County has agreed to make payment in the total amount of $62 million to be paid in four equal installments of $15.5 million commencing on December 30, 2021, with the final payment due no later than December 30, 2024, inclusive of principal and statutory interest in full settlement of all possible claims KeySpan Gas East Corporation may have against the County on this matter. KeySpan Gas East Corporation recorded an undiscounted receivable for $62 million. The benefit was reported as a credit against other taxes of $33 million for the principal portion, Other income, net of $27 million for the interest portion, and Operations and maintenance for $2 million for the costs to achieve the settlement. As authorized in an order of the NYPSC approved in 2007, KeySpan Gas East Corporation is allowed to retain the full settlement related to this litigation for the benefit of shareholders.

Financial Guarantees

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, 2024, 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.

FERC ROE Complaints

Four separate complaints have been filed at the FERC by combinations of New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (collectively the "Complainants"). In each of the first three complaints, filed on October 1, 2011, December 27, 2012, and July 31, 2014, respectively, the Complainants challenged the NETO, of which NEP is one, base ROE of 11.14% that had been utilized since 2005 and sought an order to reduce it prospectively from the date of the final FERC order and for the separate 15-month complaint periods. In the fourth complaint, filed April 29, 2016, the Complainants challenged the NETOs' base ROE of 10.57% and the maximum ROE for transmission incentive ("incentive cap") of 11.74%, asserting that these ROEs were unjust and unreasonable. NEP recorded a liability of $38 million and $39 million included in miscellaneous current and accrued liabilities on the consolidated balance sheets as of March 31, 2024 and 2023, respectively, for the potential refund as a result of reduction of the base ROE.

With the exception of the FERC order issued on October 16, 2018, where the FERC proposed a new framework to determine whether an existing ROE is unjust and unreasonable and, if so, how to calculate a replacement ROE, the FERC has not issued a final order on NEP’s ROE complaints nor the applicability of the FERC orders on the MISO ROE complaint proceedings on other transmission owners.

Given the significant uncertainty relating to the October 2018 FERC order and the subsequent orders issued on the MISO ROE complaint proceedings, NEP has concluded that there is no reasonable basis for a change to the reserve or recognized ROEs for any of the complaint periods at this time. Further, NEP believes that the current reserve is the best estimate of the potential loss.

Nuclear Contingencies

As of March 31, 2024 and 2023, Niagara Mohawk had a liability of $193 million and $183 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 provides three payment options for liquidating such liability and Niagara Mohawk has elected to delay payment, with interest, until the year in which Constellation Energy Group Inc., which purchased Niagara Mohawk’s nuclear assets, initially plans to ship irradiated fuel to an approved Department of Energy (“DOE”) disposal facility.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository. A Blue-Ribbon Commission ("BRC") on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that was planned to be operational in 2025. However, due to continued delays on the part of the DOE, and the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term spent nuclear fuel storage, the Company cannot predict the date at which the DOE will begin accepting spent nuclear fuel.

In the Consolidated Appropriations Act, 2021, Congress appropriated funds to the Department for interim storage activities. Interim storage is an important component of a waste management system and will enable near-term consolidation and temporary storage of spent nuclear fuel. This will allow for removal of spent nuclear fuel from reactor sites, provide useful research opportunities, and build trust and confidence with stakeholders and the public by demonstrating a consent-based approach to siting.

DOE anticipates that an interim storage facility would need to operate until the fuel can be moved to final disposal. The duration of the interim period depends on the completion of a series of significant steps, such as the need to identify, license, and construct a facility, plus the time needed to move the spent nuclear fuel.

Amended and Restated Power Supply Agreements

Effective May 28, 2013 (and most recently amended on April 1, 2018), Genco provides services to LIPA under an amended and restated ("A&R") PSA. Under the A&R PSA, Genco has a return on equity of 9.75% 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 of 62.5% of the unit's net book value. In April 2024, Genco received notices from LIPA requesting the ramp down of West Babylon Unit 4, Glenwood Unit 1, and Shoreham Unit 2, with the effective retirement date of May 1, 2025.

On April 18, 2022, Genco and LIPA signed a "Letter Agreement to Clarify and Settle Ramp Down Rights and Other Issues under the A&R PSA" ("Letter Agreement"), and on September 22, 2022, GENCO and LIPA signed a "Side Letter to Clarify Post Nassau Tax Settlement Administration of LIPA/National Grid Obligations" ("Side Letter"). In November 2022, GENCO submitted amendments to the A&R PSA to reflect the terms of the Letter Agreement and the Side Letter which were approved by the FERC on January 27, 2023, with an effective date of February 1, 2023. 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 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.

Effective 2022, the base property tax amount for each year is the prior year's actual property tax amount recorded on Genco's books, increased by 4% and subject to further adjustments for any known and measurable changes for the current year. The capacity charge is changed each year to reflect the new base year amount. Any differences between the base year property tax amount and the actual property tax amount recorded on Genco's books in each year are deferred by Genco. The deferred amount, inclusive of carrying charges, is billed or credited to LIPA in the fourth month following the year being trued-up.

Effective 2023, Genco no longer makes property tax payments on behalf of LIPA to Nassau County for certain real properties associated with the Barrett and Glenwood Generating Facilities.

17. 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 noncurrent operating lease liabilities on the consolidated balance sheets. As of March 31, 2024 and 2023, the Company does not have any finance leases.

Expense related to operating leases was $131 million and $153 million for the years ended March 31, 2024 and 2023, respectively.

As of March 31, 2024, 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,	
	2024	**2023**
	(in millions of dollars)	
Cash paid for amounts included in lease liabilities		
Operating cash flows from operating leases	**$ 133**	$ 152
ROU assets obtained/(released) in exchange for operating lease liabilities	**$ 194**	$ 309
Weighted-average remaining lease term – operating leases	**10 years**	10 years
Weighted-average discount rate – operating leases	**3.81%**	3.05%

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 cash flows of the operating lease liabilities recognized in the comparative balance sheet:

	As of March 31, 2024 Operating Leases
Year Ending March 31,	*(in millions of dollars)*
2025	$ 128
2026	117
2027	109
2028	99
2029	85
Thereafter	528
Total future minimum lease payments	1,066
Less: imputed interest	224
Total	$ 842
Reported as of March 31, 2024:	
Current lease liability	$ 101
Non-current lease liability	741
Total	$ 842

Genco recognizes operating revenue 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 $457 million and $478 million for the years ended March 31, 2024 and March 31, 2023, respectively.

There are other lease arrangements where the Company is the lessor. Revenue under such leases was immaterial for the years ended March 31, 2024 and March 31, 2023.

18. 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 Unconsolidated Affiliates		**Accounts Payable to Unconsolidated Affiliates**	
	March 31,		**March 31,**	
	2024	2023	**2024**	2023
	(in millions of dollars)			
National Grid plc	**$ 95**	$ 38	**$ 104**	$ 81
Total	**$ 95**	$ 38	**$ 104**	$ 81

The above accounts receivable from affiliate balances of $95 million and $38 million are included in other current assets, net as of March 31, 2024 and 2023, respectively.

Advance from Affiliate

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. These advances currently bear interest rates of SOFR 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, 2024 and 2023, the Company had zero advances under this agreement.

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, 2024 and 2023, the effect on income before income taxes was $62 million and $73 million, respectively.

19. 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, 2024 and 2023 is presented in the table below. The preferred stock is reported as a non-controlling interest as of March 31, 2024.

		Shares Outstanding		Amount		
		March 31,		March 31,		Call
Series	Company	**2024**	2023	**2024**	2023	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, 2024 or 2023. The annual dividend requirement for cumulative preferred stock was $1 million as of March 31, 2024 and 2023.

20. SALE OF NARRAGANSETT

On March 17, 2021, the Company signed an agreement to sell its 100% ownership interest in Narragansett for $3.8 billion (excluding long-term debt). The sale was agreed to as part of the Parent's acquisition of Western Power Distribution from PPL. The sale was completed on May 25, 2022, with total proceeds of $3.9 billion. A gain on sale of $847 million was recognized in the consolidated statements of operations and comprehensive income for the year ended March 31, 2023.

Following the completion of the sale, National Grid continues to provide certain transitional services to PPL under the Transition Service Agreement which has now been extended from May 25, 2024 to September 30, 2024. These services mainly include IT services, customer service call centers, customer billing operations, and electric and gas operations, which are charged to PPL at cost, plus a reasonable markup, per the terms of the Transition Service Agreement,

The Company's consolidated statements of operations and comprehensive income include $14 million for the year ended March 31, 2023, of Income before income taxes resulting directly from the operations of Narragansett.