The Narraganset Electric Company

Financial Statements

For the years ended March 31, 2021, 2020, and 2019

THE NARRAGANSETT ELECTRIC COMPANY

TABLE OF CONTENTS

Deloitte.

Deloitte & Touche LLP
30 Rockefeller Plaza
New York, NY 10112
USA

Tel: +1 212 492 4000
Fax: +1 212 489 1687
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
The Narragansett Electric Company

We have audited the accompanying financial statements of The Narragansett Electric Company (the "Company"), which comprise the balance sheets and statements of capitalization as of March 31, 2021 and 2020 and the related statements of income, cash flows, and changes in shareholders' equity for each of the three years in the period ended March 31, 2021, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements 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, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Narragansett Electric Company as of March 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended March 31, 2021 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note 1 and Note 5 to the financial statements, National Grid USA has agreed to sell 100 percent of the outstanding shares of common stock in the Company to PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation. Our opinion is not modified with respect to this matter.

Deloitte & Touche LLP

September 27, 2021

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF INCOME
(in thousands of dollars)

	Years Ended March 31,		
	2021	2020	2019
Operating revenues	**$ 1,547,789**	$ 1,556,566	$ 1,556,597
Operating expenses:			
Purchased electricity	**360,686**	406,596	439,140
Purchased gas	**162,502**	158,387	173,829
Operations and maintenance	**520,548**	530,156	507,911
Depreciation	**133,770**	118,428	111,095
Other taxes	**142,387**	136,976	135,020
Total operating expenses	**1,319,893**	1,350,543	1,366,995
Operating income	**227,896**	206,023	189,602
Other income and (deductions):			
Interest on long-term debt	**(63,654)**	(55,433)	(51,573)
Other interest, including affiliate interest, net	**(1,930)**	(4,385)	(4,060)
Other income, net	**2,490**	3,096	468
Total other deductions, net	**(63,094)**	(56,722)	(55,165)
Income before income taxes	**164,802**	149,301	134,437
Income tax expense	**29,826**	26,895	24,001
Net income	**$ 134,976**	$ 122,406	$ 110,436

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

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

	Years Ended March 31,		
	2021	2020	2019
Operating activities:			
Net income	**$ 134,976**	$ 122,406	$ 110,436
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**133,770**	118,428	111,095
Regulatory amortizations	**426**	427	(1,580)
Deferred income tax	**10,657**	2,975	36,399
Bad debt expense	**33,140**	38,360	23,856
Amortization of debt discount and issuance costs	**630**	471	412
Pension and postretirement benefit expenses, net	**(1,510)**	1,562	(3,203)
Pension and postretirement benefit contributions	**(4,273)**	(4,542)	(12,294)
Environmental remediation payments	**(5,684)**	(1,932)	(1,847)
Changes in operating assets and liabilities:			
Accounts receivable, net and unbilled revenues	**(98,413)**	18,340	(35,717)
Accounts receivable from/payable to affiliates, net	**8,244**	2,692	42,975
Inventory	**1,160**	(526)	(4,406)
Regulatory assets and liabilities, net	**18,514**	(86,207)	66,431
Derivative instruments	**(7,935)**	15,089	(3,511)
Prepaid and accrued taxes	**6,240**	12,551	14,707
Accounts payable and other liabilities	**55,639**	(25,728)	30,294
Other, net	**14,558**	3,272	(15,375)
Net cash provided by operating activities	**300,139**	217,638	358,672
Investing activities:			
Capital expenditures	**(346,413)**	(314,935)	(305,013)
Intercompany money pool	**(158,550)**	-	-
Cost of removal	**(24,910)**	(26,043)	(26,652)
Other	**(2,042)**	175	(480)
Net cash used in investing activities	**(531,915)**	(340,803)	(332,145)
Financing activities:			
Common stock dividends to Parent	**-**	-	(85,250)
Preferred stock dividends	**(110)**	(110)	(110)
Payments on long-term debt	**(11,375)**	(251,375)	(15,839)
Issuance of long-term debt	**600,000**	-	350,000
Payment of debt issuance costs	**(2,839)**	-	(1,893)
Intercompany money pool	**(351,415)**	294,868	(271,647)
Equity infusion from Parent	**-**	75,000	-
Net cash provided by (used in) financing activities	**234,261**	118,383	(24,739)
Net increase (decrease) in cash, cash equivalents, restricted cash and special deposits	**2,485**	(4,782)	1,788
Cash, cash equivalents, restricted cash and special deposits, beginning of year	**3,871**	8,653	6,865
Cash, cash equivalents, restricted cash and special deposits, end of year	**$ 6,356**	$ 3,871	$ 8,653
Supplemental disclosures:			
Interest paid	**$ (53,243)**	$ (55,612)	$ (50,639)
Income taxes (paid) refunded	**(220)**	(11,107)	15,746
Significant non-cash items:			
Capital-related accruals included in accounts payable	**11,070**	10,516	12,625
Parent tax loss allocation	**2,675**	-	-

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

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2021	March 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 5,990**	$ 3,420
Restricted cash and special deposits	**366**	451
Accounts receivable	**314,047**	233,444
Allowance for doubtful accounts	**(63,390)**	(43,288)
Accounts receivable from affiliates	**17,386**	19,674
Intercompany moneypool asset	**158,550**	-
Unbilled revenues	**62,295**	57,523
Inventory	**44,015**	41,702
Regulatory assets	**71,917**	98,179
Derivative instruments	**5,010**	154
Other	**11,324**	2,873
Total current assets	**627,510**	414,132
Property, plant and equipment, net	**3,734,291**	3,470,757
Non-current assets:		
Regulatory assets	**451,963**	513,869
Goodwill	**724,810**	724,810
Other	**30,038**	41,318
Total non-current assets	**1,206,811**	1,279,997
Total assets	**$ 5,568,612**	$ 5,164,886

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

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2021	March 31, 2020
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 147,033**	$ 139,474
Accounts payable to affiliates	**60,387**	54,431
Intercompany moneypool liability	**-**	351,415
Current portion of long-term debt	**1,375**	11,375
Taxes accrued	**55,149**	43,022
Customer deposits	**11,519**	11,733
Interest accrued	**16,072**	6,676
Regulatory liabilities	**108,573**	94,664
Derivative instruments	**6,084**	11,768
Renewable energy certificate obligations	**31,372**	19,878
Environmental remediation costs	**22,588**	13,938
Other	**77,453**	43,662
Total current liabilities	**537,605**	802,036
Other non-current liabilities:		
Regulatory liabilities	**565,774**	556,768
Asset retirement obligations	**9,399**	9,738
Deferred income tax liabilities, net	**392,222**	367,318
Postretirement benefits	**32,420**	122,176
Environmental remediation costs	**89,247**	105,841
Other	**41,999**	35,208
Total other non-current liabilities	**1,131,061**	1,197,049
Commitments and contingencies (Note 13)		
Capitalization:		
Shareholders' equity	**2,390,844**	2,253,115
Long-term debt	**1,509,102**	912,686
Total capitalization	**3,899,946**	3,165,801
Total liabilities and capitalization	**$ 5,568,612**	$ 5,164,886

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

			March 31,	
			2021	2020
Total shareholders' equity			**$ 2,390,844**	$ 2,253,115
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Notes	5.64%	March 15, 2040	**300,000**	300,000
Senior Notes	4.17%	December 10, 2042	**250,000**	250,000
Senior Notes	3.92%	August 1, 2028	**350,000**	350,000
Senior Notes	3.40%	April 9, 2030	**600,000**	-
			1,500,000	900,000
First Mortgage Bonds ("FMB"):				
FMB Series N	9.63%	May 30, 2020	**-**	10,000
FMB Series O	8.46%	September 30, 2022	**12,500**	12,500
FMB Series P	8.09%	September 30, 2022	**1,250**	1,875
FMB Series R	7.50%	December 15, 2025	**3,750**	4,500
			17,500	28,875
Total debt			**1,517,500**	928,875
Unamortized debt discount			**(1,551)**	(1,646)
Unamortized debt issuance costs			**(5,472)**	(3,168)
Total debt less unamortized costs			**1,510,477**	924,061
Current portion of long-term debt			**1,375**	11,375
Total long-term debt			**1,509,102**	912,686
Total capitalization			**$ 3,899,946**	$ 3,165,801

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

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

	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2018	**$ 56,624**	**$ 2,454**	**$ 1,358,057**	**$ 931**	**$ 1,301**	**$ (2,973)**	**$ (741)**	**$ 614,509**	**$ 2,030,903**
Net income	-	-	-	-	-	-	-	110,436	110,436
Other comprehensive income (loss):									
Unrealized loss on securities, net of $3 tax benefit	-	-	-	(12)	-	-	(12)	-	(12)
Change in pension and other postretirement obligations, net of $182 tax benefit	-	-	-	-	(683)	-	(683)	-	(683)
Unrealized gains on hedges, net of $67 tax expense	-	-	-	-	-	254	254	-	254
Total comprehensive income									109,995
Common stock dividends to Parent	-	-	-	-	-	-	-	(85,250)	(85,250)
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Impact of adoption of recognition and measurement of financial assets and liabilities standard	-	-	-	(896)	-	-	(896)	896	-
Balance as of March 31, 2019	**$ 56,624**	**$ 2,454**	**$ 1,358,057**	**$ 23**	**$ 618**	**$ (2,719)**	**$ (2,078)**	**$ 640,481**	**$ 2,055,538**
Net income	-	-	-	-			-	122,406	122,406
Other comprehensive income (loss):									
Unrealized gain on securities, net of $42 tax expense	-	-	-	158	-	-	158	-	158
Change in pension and other postretirement obligations, net of $34 tax benefit	-	-	-	-	(127)	-	(127)	-	(127)
Unrealized gains on hedges, net of $66 tax expense	-	-	-	-	-	250	250	-	250
Total comprehensive income									122,687
Equity infusion from Parent	-	-	75,000	-	-	-	-	-	75,000
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Impact of adoption of reclassification of certain tax from accumulated other comprehensive income standard	-	-	-	8	(1,409)	(664)	(2,065)	2,065	-
Balance as of March 31, 2020	**$ 56,624**	**$ 2,454**	**$ 1,433,057**	**$ 189**	**$ (918)**	**$ (3,133)**	**$ (3,862)**	**$ 764,842**	**$ 2,253,115**
Net income	-	-	-	-			-	134,976	134,976
Other comprehensive income:									
Unrealized gain on securities, net of $4 tax expense	-	-	-	15	-	-	15	-	15
Change in pension and other postretirement obligations, net of $4 tax expense	-	-	-	-	14	-	14	-	14
Unrealized gains on hedges, net of $42 tax expense	-	-	-	-	-	159	159	-	159
Total comprehensive income									135,164
Parent tax loss allocation	-	-	2,675	-	-	-	-	-	2,675
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2021	**$ 56,624**	**$ 2,454**	**$ 1,435,732**	**$ 204**	**$ (904)**	**$ (2,974)**	**$ (3,674)**	**$ 899,708**	**$ 2,390,844**

The Company had 1,132,487 shares of common stock authorized, issued and outstanding, with a par value of $50 per share and 49,089 shares of cumulative preferred stock authorized, issued and outstanding, with a par value of $50 per share at March 31, 2021 and 2020.

THE NARRAGANSETT ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

The Narragansett Electric Company ("the Company") is a retail distribution company providing electric service to approximately 509,000 customers and gas service to approximately 274,000 customers in 38 cities and towns in Rhode Island. The Company's service area covers substantially all of Rhode Island.

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

On March 18, 2021 it was announced that the Company will be sold to PPL Corporation, as part of a transaction with National Grid PLC in which National Grid PLC will acquire PPL Corporation's Western Power Distribution. The expected sale proceeds is $3.8 billion, and the sale is expected to be completed in March 2022 once all regulatory approvals are obtained.

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

The novel coronavirus ("COVID-19") pandemic has disrupted the U.S. and global economies and continues to have a significant impact on global health. In March 2020, COVID-19 was declared a pandemic by the World Health Organization ("WHO") and the Centers for Disease Control and Prevention. In March 2020, the Company ceased certain customer cash collection activities in response to regulatory instructions and to changes in State, Federal and City level regulations and guidance, and actions to minimize risk to employees. The Company has also ceased customer termination activities as requested by relevant local authorities.

The Company has seen adverse impacts from COVID-19 on earnings and cash flow. Earnings are impacted by increased incremental costs, increased bad debt expense, lower capitalization rates of workforce costs, and reduced late payment revenues, slightly offset by reduced costs and other mitigation efforts by the Company. Cash flow is negatively impacted by the higher level of operating costs, and lower cash collections from customers because of the moratorium on disconnections and the economic slowdown resulting from the COVID-19 pandemic, including: (1) increase in aged receivables and bad debt expenses, (2) lost revenue from unassessed late payment charges, and (3) changes to the Company for other fees that the Company has waived pursuant to the PUC's orders. As of March 31, 2021, the Company recorded additional reserves for uncollectible accounts related to the COVID-19 pandemic's impact on the Company's electric and gas businesses.

Despite the negative impacts on cash flow, the Company has maintained access to National Grid's money pool, which has insulated the Company from immediate impacts on liquidity. Similarly, there has also been no impact on access to capital at present.

The Company has evaluated subsequent events and transactions through September 27, 2021, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the financial statements as of and for the year ended March 31, 2021. The Company continues to evaluate the ongoing impact of COVID-19 on both customers and financial performance and is complying with the request from the Rhode Island Public Utilities Commission ("RIPUC") to share relevant information.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to U.S. GAAP, the Company must make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities included in the financial statements. Such estimates and assumptions include the impact of the ongoing COVID-19 pandemic and are reflected in the accompanying financial statements. Actual results could differ from those estimates.

Regulatory Accounting

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

Revenue Recognition

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

Other Taxes

The Company collects taxes and fees from customers such as sales taxes, other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of 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, 2021, 2020, and 2019 were $54.7 million, $54.8 million, and $54.9 million, respectively.

The Company's policy is to accrue for property taxes on a calendar year basis.

Income Taxes

Federal 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 enough future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that the Company will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount.

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

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

Cash and Cash Equivalents

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

Restricted Cash and Special Deposits

Restricted cash and special deposits consists of collateral paid to the Company's counterparties for outstanding derivative instruments. The Company had restricted cash and special deposits of $0.4 million and $0.5 million as of March 31, 2021 and 2020, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based on a variety of factors including, for each type of receivable, applying an estimated reserve percentage to each aging category, taking into account historical collection and write-off experience, and management's assessment of collectability from individual customers, as appropriate. The collectability of receivables is continuously assessed and, if circumstances change, the allowance is adjusted accordingly. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated and the balances are deemed to be uncollectible. The Company recorded bad debt expense of $33.1 million, $38.4 million and $23.9 million for the years ended March 31, 2021, 2020 and 2019, respectively, within operation and maintenance expenses in the accompanying statements of income. For the years ended March 31, 2021 and 2020, bad debt expense reflects the estimated impact of COVID-19.

Inventory

Inventory is composed of materials and supplies, purchased Renewable Energy Certificates ("RECs"), and gas in storage. Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. Purchased RECs are stated at cost. There were no significant write-offs of obsolete inventory for the years ended March 31, 2021, 2020, or 2019.

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 gas purchased, 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 RIPUC.

The Company had materials and supplies of $12.8 million and $12.0 million, purchased RECs of $22.0 million and $18.5 million, and gas in storage of $9.3 million and $11.2 million as of March 31, 2021 and 2020, respectively.

Renewable Energy Standard Obligation

RECs are stated at cost and are used to measure compliance with State renewable energy standards. RECs support new renewable generation standards and are held primarily to be utilized in fulfillment of the Company's compliance obligations. As of March 31, 2021, and 2020, the Company recorded a renewable energy standard obligation of $31.4 million and $19.9 million, respectively, within renewable energy certificate obligations.

Derivative Instruments

The Company uses derivative instruments to manage commodity price risk. All derivative instruments, except those that qualify for the normal purchase normal sale exception, are recorded on the balance sheet at fair value. All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Regulatory assets or regulatory liabilities are recorded to defer the recognition of unrealized losses or gains on derivative instruments, respectively. The gains or losses on the settlement of these contracts are recognized as purchased gas on the statements of income and then refunded to, or collected from, customers consistent with regulatory requirements.

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 were to determine that a contract no longer qualifies for the normal purchase normal sale exception, then the Company would recognize the fair value of the contract and account for the gains and losses using the regulatory accounting described above.

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 recorded within restricted cash and special deposits on the balance sheet.

Fair Value Measurements

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

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

Property, Plant and Equipment

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

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the FERC and RIPUC. The average composite rates for the years ended March 31, 2021, 2020 and 2019 are as follows:

	Composite Rates		
	March 31,		
	2021	2020	2019
Electric	**3.0%**	2.9%	3.0%
Gas	**3.1%**	3.1%	3.4%

Depreciation expense includes a component for the estimated cost of removal, which is recovered through rates charged to customers. Any difference in cumulative costs recovered and costs incurred is recognized as a regulatory liability. 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 liability. The Company recognized a regulatory liability for the amount that was in excess of costs incurred of $238.9 million and $226.3 million as of March 31, 2021 and 2020, respectively.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. The equity component of AFUDC is reported in the accompanying statements of income as non-cash income in other income, net. The debt component of AFUDC is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rates. The Company recorded AFUDC related to equity of $5.8 million, $1.7 million, and $4.3 million, and AFUDC related to debt of $2.3 million, $2.0 million, and $2.5 million, for the years ended March 31, 2021, 2020, and 2019, respectively. The average AFUDC rates for the years ended March 31, 2021, 2020, and 2019 were 7.5%, 4.4%, and 5.7% respectively.

Impairment of Long-Lived Assets

The Company tests the impairment of long-lived assets when events or changes in circumstances indicate that the carrying amount of the asset (or asset group) may not be recoverable. If identified, the recoverability of an asset is determined by comparing its carrying value to the estimated undiscounted cash flows that the asset is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of the carrying value over the estimated fair value. For the years ended March 31, 2021, 2020, and 2019, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on January 1, or more frequently if events occur or circumstances exist that indicate it is more likely than not that the fair value of the Company is below its carrying amount. The Company has early adopted Accounting Standards Update ("ASU") No. 2017-04, "Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment," which eliminates step two from the two-step goodwill impairment test previously required under the former standard. The goodwill impairment test requires a recoverability test performed based on the comparison of the Company's estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, the Company is required to recognize an impairment charge for such excess, limited to the carrying amount of goodwill.

The Company elected to perform a qualitative assessment to determine whether it is more likely than not that the carrying value of the Company exceeds its estimated fair value and an impairment exists. The qualitative assessment is commonly referred to as the "Step 0" test and requires the Company to evaluate relevant events and circumstances including, but not limited to, macroeconomic conditions, industry and market considerations, cost factors, and other relevant entity-specific events that may indicate the existence of a decline in fair value that is other than temporary. The qualitative assessment indicated that it was more likely than not that the fair value of the Company exceeds its carrying value and, as such, no impairment loss exists for the year ended March 31, 2021. The Company did not record any goodwill impairment during the years ended March 31, 2021, 2020 and 2019.

Employee Benefits

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

Supplemental Executive Retirement Plans

The Company has corporate assets included in other non-current assets on the balance sheet representing funds designated for Supplemental Executive Retirement Plans, nonqualified retirement and deferred compensation benefits. These funds are invested in corporate owned life insurance policies and securities primarily consisting of equity investments and investments in municipal and corporate bonds. The corporate owned life insurance investments are measured at cash surrender value or at fair value, with increases and decreases in the value of these assets recorded in the accompanying statements of income.

Leases

The Company adopted Topic 842 during the year ended March 31, 2020. The Company elected the practical expedient "package" in which any expired contracts were not reassessed to determine whether they met the definition of a lease; classification of leases that commenced prior to the adoption of this standard was not reassessed; and any initial direct costs for existing leases were not reassessed. Additionally, the Company elected the practical expedient to not reassess existing easements that were not previously accounted for as leases under Topic 840.

The Company has elected to not evaluate whether sales tax and other similar taxes are lessor and lessee costs. Instead, such costs are deemed lessee costs. The Company does not combine lease and non-lease components for contracts in which the Company is the lessee or the lessor.

Certain building leases provide the Company with an option to extend the lease term. The Company has included the periods covered by an extension options in its determination of the lease term when management believes it is reasonably certain the Company will exercise its option.

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, 2021 and 2020. The Company does not reflect short-term leases on the balance sheets. Expense related to short-term leases was not material for the years ended March 31, 2021 and 2020.

Right-of-use 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. Right-of-use assets are amortized over the lease term.

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

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Fair Value

In August 2018, the Financial Accounting Standards Board ("FASB") issued ASU No. 2018-13 "Fair Value Measurement (Topic 820): Disclosure Framework–Changes to the Disclosure Requirements for Fair Value Measurement" which modifies certain disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement, including certain disclosure requirements relating to Level 3 fair value measurements, and eliminates disclosure requirements for transfers between Level 1 and Level 2 fair value measurements. The standard also added certain other disclosure requirements for Level 3 fair value measurements. The Company adopted this new guidance on April 1, 2020 requiring certain revisions to disclosures related to recurring fair value measurements in Note 8, "Fair Value Measurements. Upon adoption, the amendments in the standard were applied retrospectively to all periods presented, except the amendments on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements, and the narrative description of measurement uncertainty, which were applied prospectively for only the most recent annual period presented. The amendments did not materially affect the Company's disclosures and did not affect the Company's financial position, results of operations, or cash flows.

Pension and Postretirement Benefits

In August 2018, the FASB issued ASU No. 2018-14 "Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans," which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans and eliminates certain disclosure requirements. The Company adopted this new guidance on April 1, 2020 using a retrospective basis to all periods presented, resulting in certain revisions to disclosures related to the Company's defined benefit plans in Note 9, "Employee Benefits". The amendments did not materially affect the Company's disclosures related to its defined benefit postretirement benefit plans and did not affect the Company's financial position, results of operations, or cash flows.

Internal-Use Software

In August 2018, the FASB issued ASU No. 2018-15 "Intangibles–Goodwill and Other–Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that Is a Service Contract" to help entities evaluate the accounting for fees paid by a customer under a cloud computing arrangement that is a service contract. The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Under this standard, the Company applies Subtopic 350-40 to determine which implementation costs related to a hosting arrangement should be capitalized or expensed. The Company expenses the capitalized implementation costs of a hosting arrangement that is a service contract over the term of the arrangement. The Company adopted this new guidance prospectively on April 1, 2020. The amendments did not materially impact the Company's financial position, results of operations, or cash flows.

Accounting Guidance Not Yet Adopted

Income Taxes

In December 2019, the FASB issued ASU No. 2019-12 "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes" which simplifies various aspects of the accounting for income taxes by eliminating certain exceptions to current requirements. The standard also enhances and simplifies other requirements, including tax basis step-up in goodwill obtained in a transaction that is not a business combination, ownership changes in investments, and interim-period accounting for enacted changes in tax law. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. For all other entities, the standard is effective for fiscal years beginning after December 15, 2021, and interim periods within fiscal years beginning after December 15, 2022. Early adoption is permitted.

The Company plans to early adopt this standard on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

Investments – Equity Securities

In January 2020, the FASB issued ASU No. 2020-01 "Investments—Equity Securities (Topic 321), Investments—Equity Method and Joint Ventures (Topic 323), and Derivatives and Hedging (Topic 815): Clarifying the Interactions between Topic 321, Topic 323, and Topic 815 (a consensus of the FASB Emerging Issues Task Force)" which clarifies that an entity should consider transaction prices for purposes of measuring the fair value of certain equity securities immediately before applying or upon discontinuing the equity method. This accounting standard also clarifies that when accounting for contracts entered into to purchase equity securities, an entity should not consider whether, upon the settlement of the forward contract or exercise of the purchased option, the underlying securities would be accounted for under the equity method or the fair value option. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. For all other entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2021. Early adoption is permitted. The Company plans to early adopt this standard on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

Callable Debt Securities

In October 2020, the FASB issued ASU No. 2020-08 "Codification Improvements to Subtopic 310-20, Receivables – Nonrefundable Fees and Other Costs" to clarify that an entity must reevaluate whether a callable debt security with multiple call dates is within the scope of paragraph ASC 310-20-35-33 for each reporting period such that the premium should be amortized over the period ending at the earliest call date. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Early application is not permitted for public business entities. The Company will adopt this standard prospectively on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

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. For the Company, the requirements in these updates, as amended in November 2019 by ASU 2019-10 "Financial Instruments—Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates", will be effective for fiscal years beginning after December 15, 2022 (beginning April 1, 2023 for the Company), including interim periods within those fiscal years. The Company is currently assessing the application of this standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Reclassifications

Certain reclassifications have been made to the 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 shareholders' equity as previously reported.

3. REVENUE

The following table presents, for the years ended March 31, 2021, 2020 and 2019, 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		
	2021	2020	2019
	(in thousands of dollars)		
Revenue from contracts with customers:			
Electric services	**$ 1,135,865**	$ 1,055,161	1,130,618
Gas distribution	**457,123**	416,015	482,793
Total revenue from contracts with customers	**1,592,988**	1,471,176	1,613,411
Revenue from regulatory mechanisms	**(45,199)**	85,390	(56,814)
Total operating revenues	**$ $1,547,789**	$ 1,556,566	1,556,597

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 owns and maintains an electric and natural gas distribution network in Rhode Island. Distribution revenues are primarily from the sale of electricity, gas, and related services to retail customers. Distribution sales are regulated by the RIPUC, which is responsible for determining the prices and other terms of services as part of the rate making 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 and along with a return on investment.

The performance obligation related to distribution sales is to provide electricity and natural gas to customers on demand. The electricity and natural gas supplied under the respective tariff each 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 the 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.

The 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.

Additionally, the Company owns an electric transmission system in Rhode Island. Transmission systems generally include overhead lines, underground cables, and substations, connecting generation and interconnectors to the distribution system. The Company's transmission services are regulated by both the Independent System Operator ("ISO") – New England and by the FERC. Additionally, the Company makes available its transmission facilities to New England Power ("NEP," an NGUSA affiliate), for operation and control pursuant to an integrated facilities agreement, Service Agreement No. 23 (Integrated Facilities Agreement or "IFA"). See Note 15 "Related Party Transactions" for additional details. These revenues arise under tariff/rate agreements and are collected primarily from the Company's Rhode Island distribution customers.

Revenue from Regulatory Mechanisms: The Company records revenues in accordance with accounting principles for rate-regulated operations for arrangements between the Company and the regulator, which are not accounted for as contracts with customers. These include various deferral mechanisms such as capital trackers, energy efficiency programs, and other programs that also qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the Company to adjust rates in the future, in response to past activities or completed events. The Company's electric and gas distribution rates both have a revenue decoupling mechanism ("RDM"), which allows for annual adjustments to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed revenue. The Company also has other ARPs related to the achievement of certain objectives, demand side management initiatives, and certain other rate making mechanisms. The Company recognizes 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.

4. REGULATORY ASSETS AND LIABILITIES

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

	March 31, 2021	March 31, 2020
	(in thousands of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 6,221**	$ 14,157
Rate adjustment mechanisms	**52,648**	72,805
Renewable energy certificates	**9,416**	1,395
Revenue decoupling mechanism	**-**	8,474
Other	**3,632**	1,348
Total	**71,917**	98,179
Non-current:		
Environmental response costs	**110,009**	119,020
Net metering	**37,669**	26,252
Postretirement benefits	**122,878**	214,448
Storm costs	**131,382**	120,207
Other	**50,025**	33,942
Total	**$ 451,963**	$ 513,869
Regulatory liabilities		
Current:		
Energy efficiency	**$ 21,154**	$ 20,654
Gas cost adjustment	**-**	2,894
Rate adjustment mechanisms	**66,867**	44,561
Revenue decoupling mechanism	**14,448**	11,237
Transmission service	**4,491**	15,318
Other	**1,613**	-
Total	**108,573**	94,664
Non-current:		
Cost of removal	**238,863**	226,279
Energy efficiency	**36,330**	15,715
Environmental response costs	**16,155**	18,839
Regulatory tax liability, net	**258,705**	272,901
Other	**15,721**	23,034
Total	**$ 565,774**	$ 556,768

Other than $159.1 million of the regulatory assets summarized above ($120.4 million of Postretirement benefits, $37.7 million of Net metering deferral costs and $1 million other costs), all regulatory assets earn a rate of return.

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

Derivative instruments: The Company evaluates open 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 RIPUC.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs, with variances deferred for future recovery from, or return to, customers. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation costs.

Gas costs adjustment: The Company is subject to rate adjustment mechanisms for commodity costs, whereby an asset or liability is recognized resulting from differences between billed revenues and the underlying cost being recovered, as approved by the RIPUC. These amounts will be refunded to, or recovered from, customers over the next year.

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

Postretirement benefits: The regulatory asset represents the Company's unamortized non-cash accrual of net actuarial gains and losses, offset by the excess amounts received in rates over actual costs of the Company's pension and PBOP plans, that are to be recovered from or passed back to customers in future periods.

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 RIPUC.

Regulatory tax liability, net: Represents over-recovered federal deferred taxes of the Company primarily as a result of regulatory flow through accounting treatment 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 obligation with the Rhode Island Renewable Portfolio Standard ("RPS"). 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 mechanism: As approved by the RIPUC, 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 and billed revenues. Any difference is recorded as a regulatory asset or regulatory liability.

Storm costs: The Company is allowed to recover storm costs from all retail delivery service customers. This balance reflects costs yet to be recovered.

Transmission service: The Company arranges transmission service on behalf of its customers and bills the costs of those services to customers, pursuant to the Company's Transmission Service Cost Adjustment Provision. Any over or under recoveries of these costs are passed on to customers receiving transmission service over the subsequent year.

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

5. RATE MATTERS

General Rate Case

On August 24, 2018 and pursuant to Report and Order No. 23823 issued May 5, 2020, the RIPUC approved the terms of an Amended Settlement Agreement (ASA). The ASA reflects an allowed return on equity ("ROE") rate of 9.275% based on a common equity ratio of approximately 51%. We are currently in year three of the multi-year rate plan (Rate Plan). On June 30, 2021, the Division consented to an extension of the term of the Rate Plan such that the Company is not required to file its next rate case so that new rates take effect no later than September 1, 2022. The ASA will remain in effect and the Company will continue to operate under the current Rate Plan until a new Rate Plan is approved by the RIPUC. The Company filed a copy of the Division consent letter with the RIPUC on July 15, 2021. Base distribution rates will remain at the existing Rate Year 3 levels until the next base rate case.

The ASA includes an Electric Transportation Initiative (the ET Initiative or Program) to facilitate the growth of Electric Vehicle (EV) adoption and scaling of the market for EV charging equipment to advance Rhode Island's zero emission vehicles and greenhouse gas emissions policy goals. The ET Initiative includes the following five components (i) Off-Peak Charging Rebate Pilot, (ii) Charging Station Demonstration Program, (iii) Discount Pilot for Direct Current Fast Charging (DCFC) Station Accounts, (iv) Fleet Advisory Services, and (v) Electric Transportation Initiative Evaluation. As of the end of Rate Year 2 The Charging Station Demonstration Program achieved 72% of ET Initiative targets for Level 2 ports and 7% of the target for DCFC ports. The ASA also includes two energy storage demonstration projects because storage is critical for achieving Rhode Island's clean energy future as it provides the ability to optimize system performance over time and allows intermittent renewable resources to make a larger contribution to overall generation; both projects are on track for timely completion.

The ASA also introduces a new incentive-only performance incentive for System Efficiency: Annual Megawatt ("MW") Capacity Savings, with maximum earnings ranging from approximately $0.4 million in 2019 to $0.9 million in 2021. In addition, the ASA identifies several additional metrics for tracking and reporting purposes only.

Recovery of Transmission Costs

The Company's transmission facilities are operated in combination with the transmission facilities of its New England affiliates, Massachusetts Electric Company ("MECO") and NEP, as a single integrated system with NEP designated as the combined operator. NEP collects the costs of the combined transmission asset pool including a return on those facilities under NEP's Tariff No. 1 from the ISO. The ISO allocates these costs among transmission customers in New England, in accordance with the ISO Open Access Transmission Tariff ("ISO-NE OATT").

According to the FERC order, the Company is compensated for its actual monthly transmission costs, with its authorized maximum ROE of 11.74% on its transmission assets. The amounts remitted by NEP to the Company for the years ended March 31, 2021, 2020 and 2019 were $159.9 million, $141.8 million, and $144.8 million, respectively, which are eliminated as operating revenues and operations and maintenance expenses within the accompanying statements of income.

On October 16, 2014, the FERC issued an order, Opinion No. 531-A, resetting the base ROE applicable to transmission assets under the ISO-NE OATT from 11.14% to 10.57% effective as of October 16, 2014 and establishing a maximum ROE of 11.74%. On March 3, 2015, the FERC issued an Order on Rehearing, Opinion No. 531-B, affirming the 10.57% base ROE and clarifying that the 11.74% maximum ROE applies to all individual transmission projects with ROE incentives previously granted by the FERC. On April 14, 2017, the U.S. Court of Appeals for the D.C. Circuit (Court of Appeals) vacated and remanded FERC's Opinion No. 531 (and successor orders), through which the FERC had lowered the New England Transmission Owners ("NETO") return on equity from 11.14% to 10.57% and capped the total incentives at 11.74%.

On October 16, 2018, the FERC issued an order on all four complaints describing how it intends to address the issues that were remanded by the Court. 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 stated that these calculations were merely preliminary and asked the parties to the New England ("NE") Complaint cases to brief FERC and check the numbers. National Grid along with other NETOs filed a brief supporting FERC's new methodology and confirming the illustrative numbers that FERC arrived at in the October 2018 order—a 10.41% base ROE. FERC has not issued a final order on our briefs and the base ROE in NE remains at a 10.57%. In November 2019, FERC issued an order in the Midcontinent Independent System Operator ("MISO") ROE complaint dockets changing the way it arrives at a just and reasonable ROE. The effects of these changes result in drastically reduced base ROEs in the MISO region. In that MISO order, FERC made statements that it is setting new ROE policy nationwide. In December 2019, the NETOs filed a supplemental brief in the NE ROE complaint dockets showing FERC the detrimental effects on NE if the MISO order were applied to NE. In that brief, the NETOs ask FERC to reopen the record in NE so that we can submit more testimony. Other stakeholders had an opportunity to reply to our supplemental brief by January 21st and did so, arguing that our request should be denied, and that the record in NE should not be reopened.

On January 21, 2020, the FERC issued an order granting rehearing for further consideration to give the FERC more time to act on the substantive issues of the MISO ROE proceedings. On May 21, 2020, FERC revised the methodology to determine MISO transmission owner ROEs. FERC's November order proposed to create "zones of reasonableness" based on averages of two (rather than four) models to judge whether ROEs are just and reasonable. ROEs were reduced from 10.32% to 9.88% when FERC applied the revised methodology in two MISO ROE complaints. The May order relies on three models to estimate ROEs. The application of this new methodology increased ROEs in the MISO complaints from 9.88% to 10.02%. The Company does not believe the outcomes of these complaints will have a material impact on the Company's financial condition, results of operations or cash flows.

Tax Act

On March 15, 2018, the FERC initiated multiple proceedings intended to adjust FERC-jurisdictional rates to reflect the corporate tax changes as a result of the passage of the Tax Act. Of the proceedings initiated relevant to the Company is the Notice of Inquiry ("NOI") seeking comments on the effects of the Tax Act on all FERC-jurisdiction rates and a Notice of Proposed Rulemaking (NOPR) issued as a result of the NOI. In response to the FERC NOI, the Company made recommendations designed to mitigate the cash flow impacts of the expected refunds including providing flexibility regarding the methods used to refund accumulated deferred income tax ("ADIT") to customers and providing flexibility regarding the time period of the flow back. In the NOPR, FERC proposed to give the flexibility the Company proposed.

On November 21, 2019, the FERC issued Order 864 to address ratemaking and regulatory reporting of excess or deficient ADIT related to the Tax Act. The order applies to public utility transmission providers with formula rates and stated rates and provides that public utilities with formula rates submit a compliance filing within 30 days of the effective date of the final rule or in the public utilities next annual informational filing following the issuance of the final rule. The compliance filing must demonstrate how the public utilities formula rate adjusts rate base via a Rate Adjustment mechanism, returns or recovers excess or deficient ADIT via an Income Tax Allowance Mechanism, and must include an ADIT worksheet to support the excess or deficient ADIT calculation and amortization. The ADIT worksheet must be populated and will be a new and permanent worksheet. The mechanisms and worksheet must remain applicable to any future changes to tax rates that give rise to excess or deficient ADIT, including changes to state and local tax rates. Excess or deficient ADIT associated with future tax rate changes will automatically be included in a public utility's formula rate without the need for a Section 205 filing. The order does not prescribe a recovery/refund period for deficient/excess ADIT for unprotected excess/deficient ADIT that is not subject to the normalization requirements. FERC will evaluate proposed amortization periods on a case by case basis. On April 16, 2020, the FERC issued Order No. 864-A addressing requests for clarification, or in the alternative, rehearing, submitted in the proceeding. FERC will evaluate proposed amortization periods on a case by case basis.

On June 29,2020, NEP, on behalf of NECO, submitted a compliance filing to address the application of Order 864 in NEP Tariff No. 1. The filing proposes changes to various revenue requirement calculations in the tariff for the inclusion of the Rate Adjustment and Income Tax Allowance Mechanism. The filing also includes the populated permanent ADIT worksheet to be provided with the issuance of final bills pursuant to the provisions of the tariff. NEP has proposed for NECO to amortize transmission related protected property related excess or deficient ADIT associated with the 2017 Tax Act using the Average Rate Adjustment Mechanism ("ARAM") and a 30-year amortization period on unprotected property related excess or deficient balances. Other unprotected excess or deficient ADIT is proposed to be amortized over 10 years consistent with periods approved in the RIPUC Docket addressing the Tax Act. NECO's transmission related net excess ADIT balance associated with the Tax Act is $99.6 million.

The RIPUC opened a docket to address the change in the federal corporate income tax rate and other changes resulting from the Tax Act that was signed into law in December 2017. Specifically, the RIPUC requested the Company's proposal for how it planned to reduce rates associated with the income taxes recovered from customers on the equity component of the return on investment included in revenue taxed at the new lower income tax rate of 21% effective January 1, 2018, and how it planned to return to customers the reduction in its net deferred income tax liabilities resulting from the 14% decrease in the federal income tax rate from 35%. Effective September 1, 2018, the Company reduced its revenue requirement for electric and gas distribution rates in effect for the impacts of the Tax Act as appropriate. On January 24, 2019, the Company filed with the RIPUC a settlement agreement among the Company, the Division, the Office of Energy Resources, and the State of Rhode Island Office of the Lieutenant Governor, pursuant to which approximately $4.8 million and $3.1 million will be provided to electric and gas customers, respectively, which reflect the benefits of the Company's reduced federal corporate income tax payment obligations for the period January 1, 2018 through August 31, 2018. The RIPUC approved the settlement agreement on May 17, 2019, as filed.

New England East-West Solution ("NEEWS") Project

In September 2008, the Company, NEP, and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the NEEWS project, pursuant to the FERC's Transmission Pricing Policy Order No. 679. NEEWS consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan and is being undertaken to address several reliability problems in Connecticut, Massachusetts, and Rhode Island. The Company's share of the NEEWS-related transmission investment was approximately $560 million. The Company is fully reimbursed for its transmission revenue requirements on a monthly basis by NEP through NEP's Tariff No. 1. Effective November 18, 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (2) 100% construction work in progress ("CWIP") in rate base, and (3) recovery of plant abandoned for reasons beyond the companies' control. As discussed in the preceding section, effective October 16, 2014, the FERC issued a series of orders establishing a maximum ROE of 11.74% that effectively caps the NEEWS incentive ROE at that level. The NEEWS upgrades were placed in service in December 2015.

Suspension of Service Terminations and Certain Collections Activities

At an open meeting on March 16, 2020, the RIPUC issued an order prohibiting all electric, natural gas, water, and sewer utilities from engaging in certain collections activities, including termination of residential and non-residential service for nonpayment (the "Order"). This moratorium expired on July 18, 2020 for commercial and industrial customers, on September 30 for residential customers, and on November 1, 2020 for customers eligible for the low-income rate. On July 25, 2021, the RIPUC's extension of the moratorium on service disconnections for National Grid's protected status customers, including those on National Grid's low-income rate, expired. Per the RIPUC's June 25, 2021 order extending the moratorium to July 25, 2021, there will be no further extensions, unless there is substantial evidence of a major resurgence of the COVID-19 Pandemic. To date, the RIPUC has not ordered any additional extensions of the moratorium so the moratorium is no longer in effect. The RIPUC's order directing the Company to temporarily suspend late fees, interest charges, credit card fees, debit card fees and ACH fees remains in effect, and the Company continues to track these costs for later review by the RIPUC. The RIPUC will review these costs in the Company's cost recovery filing in a separate docket (RIPUC Docket No. 5154). The Company continues to offer the 18-24-36-month payment plans per the RIPUC's order.

On May 15, 2020, pursuant to the RIPUC's directive, the Company filed a plan with the RIPUC and the Division that details the Company's plans for recommencing collection activities when the RIPUC lifts the moratorium on utility terminations (the "Plan"). The Plan consists of a four-phase approach, including initial efforts primarily focused on "bill health" messaging and assuring that customers are aware of the programs and services available to assist them with managing and paying their bills. The Company continues to progress through the phases of the Plan. The Company continues to submit arrearage data to the RIPUC and the Division on a weekly and monthly basis, respectively. On September 2, 2021, the Company filed its responses to the RIPUC's data requests regarding waived fees.

Advanced Metering Functionality and Grid Modernization

On January 21, 2021 the Company filed its Updated Advance Metering Functionality ("AMF") Business Case and Grid Modernization Plan ("GMP") with the RIPUC in accordance with the rate case settlement. The Updated AMF Business Case –

a foundational component of the GMP – seeks approval to deploy smart meters throughout the service territory. The Updated AMF Business Case includes approximately $224 million (20-year net present value)/$344 million (20-year nominal) of investment in smart meters and the associated communications infrastructure, as well as customer education and engagement based on a joint deployment scenario with New York. The GMP consists of a five-year implementation plan and ten-year roadmap that serve as a guide for addressing anticipated distribution system needs. Although the Company is not seeking cost recovery for any specific GMP investment at this time, the Company is seeking approval of the GMP business case and benefit-cost analysis, which will provide regulatory clarity when seeking to implement such projects and pursue cost recovery as part of the Infrastructure, Safety and Reliability Plan or a future rate case. Pursuant to written order issued on July 14, 2021, the RIPUC stayed the AMF and GMP proceedings pending further consideration following the issuance of a final Order by the Division on the PPL Transaction. The RIPUC did not rule on whether or not to consolidate the matters.

COVID-19 Deferral Filing

On April 30, 2021, the Company filed a petition for approval to recognize regulatory assets related to COVID-19 Impacts (RIPUC Docket No. 5154). In its Petition, the Company seeks the PUC's authorization to create regulatory assets and consideration of future cost recovery for the following COVID-19 Costs: (1) the increased cost of customer accounts receivable that the Company will be unable to collect as a result of the COVID-19 pandemic, and the executive orders and PUC orders restricting the Company's collection activities as a result of the pandemic, which will result in increased net charge-offs; (2) lost revenue from unassessed late payment charges; and (3) charges to the Company for other fees that the Company has waived pursuant to the RIPUC's orders in R.I.P.U.C. Docket No. 5022. We will continue to monitor the proceeding, pending any updates or new directive issued by the PUC.

Block Island Transmission System Surcharge Issues

The RIPUC has issued discovery to the Company regarding the Block Island Transmission System ("BITS") surcharge calculation during its 2021 Annual Retail Rates proceeding. During the Open Meeting in that docket, the Chairman questioned the Company's BITS arrangement. In addition, the Division has expressed ongoing concerns with the incremental costs associated with the reburial project related to the BITS cable and has retained FERC counsel. The Company is in discussions with the Division on potential options regarding these matters; however, we cannot predict the outcome of these discussions.

PPL Transaction

Pursuant to a Share Purchase Agreement dated March 17, 2021, by and among PPL Energy Holdings, LLC, PPL Corporation ("PPL"), and National Grid USA (the "Transaction"), National Grid USA has agreed to sell 100 percent of the outstanding shares of common stock in Narragansett to PPL Rhode Island Holdings, LLC ("PPL Rhode Island"), a wholly owned indirect subsidiary of PPL. On May 4, 2021, PPL, PPL Rhode Island, National Grid USA, and Narragansett filed a joint petition with the Division seeking the Division's consent and approval of the Transaction, which is currently pending in Docket No. D-21-09.

6. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2021	2020
	(in thousands of dollars)	
Plant and machinery	**$ 4,478,788**	$ 4,133,095
Land and buildings	**135,500**	129,368
Assets in constructions	**208,699**	228,897
Software and other intangibles	**25,988**	25,988
Assets held for future use	**15,028**	15,028
Operating leases	**34,271**	28,624

Total property, plant and equipment	**4,898,274**	4,561,000
Accumulated depreciation and amortization	**(1,150,582)**	(1,083,552)
Operating lease accumulated depreciation	**(13,401)**	(6,691)
Property, plant and equipment, net	**$ 3,734,291**	$ 3,470,757

7. DERIVATIVE INSTRUMENTS

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

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

The volume of outstanding gas derivative instruments as of March 31, 2021 and March 31, 2020 was 38.5 million dekatherms and 40.6 million dekatherms, respectively.

Derivative Financial Instruments

The following tables reflect the gross and net amounts of the Company's derivative assets and liabilities as of March 31, 2021 and 2020:

March 31, 2021
(in thousands of dollars)

	Gross amounts of recognized assets (liabilities)	Gross amounts offset in the Balance Sheets	Net amounts of assets (liabilities) presented in the Balance Sheets	Gross amounts not offset in the Balance Sheets	Net Amount
ASSETS:	*A*	*B*	*C=A+B*	*D*	*E=C-D*
Other current assets					
Gas contracts (rate recoverable)	$ 4,953	$ -	$ 4,953	$ 513	$4,440
Gas contracts (not subject to rate recovery)	57	-	57	55	2
Other non-current assets					
Gas contracts (rate recoverable)	630	-	630	124	506
Total	$ 5,640	$ -	$ 5,640	$ 692	$ 4,948
LIABILITIES:					
Current liabilities					
Gas contracts (rate recoverable)	$ 5,982	$ -	$ 5,982	$ 504	$ 5,478
Gas contracts (not subject to rate recovery)	102	-	102	55	47
Other non-current liabilities					
Gas contracts (rate recoverable)	5,823	-	5,823	124	5,699
Total	11,907	-	11,907	683	11,224
Net assets/(liabilities)	$ (6,267)	$ -	$ (6,267)	$ 9	$ (6,276)

	March 31, 2020 (in thousands of dollars)				
	Gross amounts of recognized assets (liabilities)	Gross amounts offset in the Balance Sheets	Net amounts of assets (liabilities) presented in the Balance Sheets	Gross amounts not offset in the Balance Sheets	Net Amount
ASSETS:	*A*	*B*	*C=A+B*	*D*	*E=C-D*
Other current assets					
Gas contracts (rate recoverable)	$ 90	$ -	$ 90	$ 90	$ -
Gas contracts (not subject to rate recovery)	64	-	64	54	10
Other non-current assets					
Gas contracts (rate recoverable)	283	-	283	77	206
Total	437	-	437	221	216
LIABILITIES:					
Current liabilities					
Gas contracts (rate recoverable)	11,658	-	11,658	135	11,523
Gas contracts (not subject to rate recovery)	110	-	110	54	56
Other non-current liabilities					
Gas contracts (rate recoverable)	2,871	-	2,871	77	2,794
Total	14,639	-	14,639	266	14,373
Net liabilities	$ (14,202)	$ -	$ (14,202)	$ (45)	$ (14,157)

The changes in fair value of the Company's rate recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, the changes in fair value of those contracts had no impact in the accompanying statements of income.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price 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.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to National Grid plc'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 Vice President of U.S. Treasury 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 net liability of $6.3 million and $14.2 million as of March 31, 2021 and March 31, 2020, 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, 2021 and March 31, 2020 was $0.1 million and $6.6 million, respectively. The Company had no collateral posted for these instruments at March 31, 2020 and March 31, 2019. If the Company's credit rating were to be downgraded by one or two levels, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three levels, it would have been required to post $0.2 million and $7.1 million of additional collateral to its counterparties at March 31, 2021 and March 31, 2020, respectively.

8. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2021 and 2020:

	March 31, 2021			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in thousands of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 5,640	$ -	$ 5,640
Securities	3,527	4,431	-	7,958
Total	3,527	10,071	-	13,598
Liabilities:				
Derivative instruments				
Gas contracts	-	9,379	2,527	11,906
Total	-	9,379	2,527	11,906
Net liabilities	$ 3,527	$ 692	$ (2,527)	$ 1,692

	March 31, 2020			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in thousands of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 437	$ -	$ 437
Securities	2,674	3,729	-	6,403
Total	2,674	4,166	-	6,840
Liabilities:				
Derivative instruments				
Gas contracts	-	9,097	5,542	14,639
Total	-	9,097	5,542	14,639
Net assets (liabilities)	$ 2,674	$ (4,931)	$ (5,542)	$ (7,799)

Derivative instruments*:* The Company's Level 2 fair value derivative instruments consist of over-the-counter ("OTC") gas swaps contracts with pricing inputs obtained from the New York Mercantile Exchange ("NYMEX") and the Intercontinental

Exchange (“ICE”), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. The Company 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 consist of gas option and purchase and capacity transactions, which are valued based on internally developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Company considers non-performance risk and liquidity risk in the valuation of derivative instruments categorized in Level 2 and Level 3.

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

Securities: Securities are included in other non-current assets on the balance sheet 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).

9. EMPLOYEE BENEFITS

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

Plan assets are maintained for all of NGUSA and its subsidiaries in commingled trusts. In respect of cost determination, plan assets are allocated to the Company based on its proportionate share of the projected benefit obligations. The Plans’ costs are first directly charged to the Company based on the Company’s employees that participate in the Plans. Costs associated with affiliated service companies’ employees are then allocated as part of the labor burden for work performed on the Company’s behalf. The Company applies deferral accounting for pension and PBOP expenses associated with its regulated gas and electric operations. Any differences between actual costs and amounts used to establish rates are deferred and collected from, or refunded to, customers in subsequent periods. Pension and PBOP service costs are included within operations and maintenance expense, and non-service costs are included within other income, net in the accompanying statements of income. Portions of the net periodic benefit costs disclosed below have been capitalized as a component of property, plant, and equipment.

Pension Plans

The Qualified Pension Plans are defined benefit plans which provide most union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2021, 2020, and 2019, the Company made contributions of approximately $4.0 million, $4.3 million, and $12.0 million, respectively, to the Qualified Pension Plans. The Company expects to contribute approximately $7.3 million to the Qualified Pension Plans during the year ending March 31, 2022.
Benefit payments to Pension Plan participants for the years ended March 31, 2021, 2020, and 2019 were approximately $28.7 million, $28.4 million, and $27.6 million, respectively.

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. For each of the years ended March 31, 2021, 2020, and 2019, the Company made zero contributions to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2022.

Benefit payments to PBOP plan participants for the years ended March 31, 2021, 2020, and 2019 were approximately $11.2 million, $9.1 million, and $9.8 million, respectively.

Net Periodic Benefit Costs

The Company’s total pension cost for the years ended March 31, 2021, 2020, and 2019 were $11.4 million, $7.0 million, and $9.8 million, respectively.

The Company’s total PBOP cost for the years ended March 31, 2021, 2020, and 2019 were $0.1 million, $1.0 million, and $2.8 million, respectively.

Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income

The following tables summarize the Company’s changes in actuarial gains/losses and prior service costs recognized in regulatory assets and accumulated other comprehensive income (“AOCI”) as of March 31, 2021, 2020, and 2019:

	Pension Plans		
	Years Ended March 31,		
	2021	2020	2019
		(in thousands of dollars)	
Net actuarial (gain) loss	**$ (46,483)**	$ 48,706	$ 7,362
Amortization of net actuarial loss	**(11,892)**	(9,222)	(9,659)
Amortization of prior service cost, net	**-**	(15)	(20)
Total	**$ (58,375)**	$ 39,469	$ (2,317)
Included in regulatory assets	**$ (58,357)**	$ 39,309	$ (3,182)
Included in AOCI	**(18)**	160	865
Total	**$ (58,375)**	$ 39,469	$ (2,317)

	PBOP Plans		
	Years Ended March 31,		
	2021	2020	2019
	(in thousands of dollars)		
Net actuarial (gain) loss	**$ (38,482)**	$ 6,752	$ (7,013)
Amortization of net actuarial loss	**(243)**	(442)	(1,275)
Amortization of prior service benefit, net	**20**	20	20
Total	**$ (38,705)**	$ 6,330	$ (8,268)
Included in regulatory assets	**$ (38,705)**	$ 6,330	$ (8,268)
Total	**$ (38,705)**	$ 6,330	$ (8,268)

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

The following tables summarize the Company's amounts in regulatory assets and accumulated other comprehensive income on the balance sheet that have not yet been recognized as components of net actuarial loss as of March 31, 2021, 2020, and 2019

	Pension Plans		
	March 31,		
	2021	2020	2019
	(in thousands of dollars)		
Net actuarial loss	**$ 134,413**	$ 192,788	$ 153,304
Prior service cost	**2**	2	17
Total	**$ 134,415**	$ 192,790	$ 153,321
Included in regulatory assets	**$ 133,272**	$ 191,629	$ 152,321
Included in AOCI	**1,143**	1,161	1,000
Total	**$ 134,415**	$ 192,790	$ 153,321

	PBOP Plans		
	March 31,		
	2021	2020	2019
	(in thousands of dollars)		
Net actuarial (gain) loss	**$ (12,905)**	$ 25,820	$ 19,510
Prior service cost (benefit)	**15**	(5)	(25)
Total	**$ (12,890)**	$ 25,815	$ 19,485
Included in regulatory assets	**$ (12,890)**	$ 25,815	$ 19,485
Total	**$ (12,890)**	$ 25,815	$ 19,485

Reconciliation of Funded Status to Amount Recognized

	Pension Plans				PBOP Plans			
	March 31,				March 31,			
	2021		2020		**2021**		2020	
	(in thousands of dollars)							
Projected benefit obligation	**$**	**(636,782)**	$	(606,064)	**$**	**(205,963)**	$	(200,662)
Fair value of plan assets		**625,259**		543,434		**184,778**		140,828
Total	**$**	**(11,523)**	$	(62,630)	**$**	**(21,185)**	$	(59,834)
Current liabilities	**$**	**(195)**	$	(196)	**$**	**(93)**	$	(92)
Other non-current liabilities		**(11,328)**		(62,434)		**(21,092)**		(59,742)
Total	**$**	**(11,523)**	$	(62,630)	**$**	**(21,185)**	$	(59,834)

For the year end March 31, 2021, the net actuarial gains for pension and PBOP was largely the result of asset performance and lower contract pricing negotiated on certain prescription benefit costs within the PBOP Plans, partially offset by losses generated from the discount rate decrease. For the year end March 31, 2020, the net actuarial loss for pension and PBOP was primarily driven by the discount rate decrease and asset performance below expectations. This loss was partially offset by a gain related to a change in the mortality assumption and a PBOP assumption change for post-65 participation rates. For the year end March 31, 2019, the net actuarial loss for pension was primarily generated by the discount rate decrease. Whereas for the PBOP plans, the net gain was driven by assumptions changes related to pre-65 participation rates, offset by the discount rate decrease.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2021:

(in thousands of dollars) Years Ended March 31,	Pension Plans		PBOP Plans	
2022	$	33,507	$	9,347
2023		34,762		9,554
2024		36,126		9,683
2025		37,458		10,035
2026		38,834		10,302
2027-2031		209,297		53,953
Total	$	389,984	$	102,874

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	As of and Years Ended March 31,		
	2021	2020	2019
Benefit Obligations:			
Discount rate	**3.25%**	3.65%	4.10%
Rate of compensation increase (nonunion)	**4.10%**	3.50%	3.50%
Rate of compensation increase (union)	**4.05%**	3.50%	3.50%
Weighted average cash balance interest crediting rate	**2.75%**	2.75%	3.25%
Net Periodic Benefit Costs:			
Discount rate	**3.65%**	4.10%	4.10%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.00%**	6.50%	6.25%
Weighted average cash balance interest crediting rate	**2.75%**	3.25%	3.00%

	PBOP Plans		
	As of and Years Ended March 31,		
	2021	2020	2019
Benefit Obligations:			
Discount rate	**3.25%**	3.65%	4.10%
Net Periodic Benefit Costs:			
Discount rate	**3.65%**	4.10%	4.10%
Expected return on plan assets	**6.50%-7.00%**	6.50%-7.25%	6.25%-6.75%

The Company selects its discount rate assumption based upon rates of return on highly rated corporate bond yields in the marketplace as of each measurement date. 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 small premium is added for active management of both equity and fixed income securities. The rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in a long-term return on asset rate for each plan.

Assumed Health Cost Trend Rate

	March 31,	
	2021	2020
Health care cost trend rate assumed for next year		
Pre 65	**6.80%**	7.00%
Post 65	**5.40%**	5.50%
Prescription	**7.70%**	8.00%
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	**2031+**	2031+

Plan Assets

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

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

The RPC has established and reviews at least annually the Investment Policy Statement ("IPS") which sets forth the guidelines for how plan assets are to be invested. The IPS contains a strategic asset allocation for each plan which is intended to meet the objectives of the plans by diversifying its funds across asset classes, investment styles and fund managers. An asset/liability study typically is conducted periodically to determine whether the current strategic asset allocation continues to represent the appropriate balance of expected risk and reward for the plan to meet expected liabilities. Each study considers the investment risk of the asset allocation and determines the optimal mix of assets for the plan. The target asset allocation for 2021 reflects the results of such a pension study conducted in 2019. The Union PBOP Plan asset liability study was conducted in 2021. As a result of that study the RPC approved changes to the Union PBOP asset allocation effective in fiscal year 2022. The Non-Union PBOP Plan asset liability study is expected to be run within the next 12-18 months.

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

Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments and is mainly invested in investment grade securities. Where investments are made in non-investment grade assets the higher volatility is carefully judged and balanced against the expected higher returns. While the majority of plan assets are invested in equities and fixed income other asset classes are utilized to further diversify the investments. These asset classes include private equity, real estate, and diversified alternatives. The objective of these other investments are 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, 2021 and 2020 are as follows:

	Pension Plans		**Union PBOP Plans**		**Non-Union PBOP Plans**	
	March 31,		**March 31,**		**March 31,**	
	2021	2020	**2021**	2020	**2021**	2020
Equity	**37%**	37%	**63%**	63%	**70%**	70%
Diversified alternatives	**10%**	10%	**17%**	17%	**0%**	0%
Fixed income securities	**40%**	40%	**20%**	20%	**30%**	30%
Private equity	**5%**	5%	**0%**	0%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%	**0%**	0%
Infrastructure	**3%**	3%	**0%**	0%	**0%**	0%
	100%	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurements amounts for the pension and PBOP assets at the Plan level:

	March 31, 2021				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in thousands of dollars)		
Pension Assets:					
Investments					
Equity	$ 244,018	$ -	$ -	$ 891,362	$ 1,135,380
Diversified alternatives	70,409	-	-	203,187	273,596
Corporate bonds	-	514,588	-	168,106	682,694
Government securities	480	294,487	-	238,270	533,237
Private equity	-	-	-	168,914	168,914
Real estate	-	-	-	110,603	110,603
Infrastructure	-	-	-	50,489	50,489
Total assets	**$ 314,907**	**$ 809,075**	**$ -**	**$ 1,830,931**	**$ 2,954,913**
Pending transactions					**(148,083)**
Total net assets					**$ 2,806,830**
PBOP Assets:					
Investments					
Equity	$ 196,570	$ -	$ -	$ 335,943	$ 532,513
Diversified alternatives	45,255	-	-	41,632	86,887
Corporate bonds	-	3,792	-	-	3,792
Government securities	14,864	157,025	-	1,032	172,921
Insurance contracts	-	-	-	43,934	43,934
Total assets	**$ 256,689**	**$ 160,817**	**$ -**	**$ 422,541**	**$ 840,047**
Pending transactions					**1,103**
Total net assets					**$ 841,150**

	March 31, 2020				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in thousands of dollars)		
Pension Assets:					
Investments					
Equity	$ 173,535	$ -	$ -	$ 630,567	$ 804,102
Diversified alternatives	57,730	-	-	173,255	230,985
Corporate bonds	-	412,698	-	142,101	554,799
Government securities	(4,072)	300,759	-	267,338	564,025
Private equity	-	-	-	131,200	131,200
Real estate	-	-	-	115,522	115,522
Infrastructure	-	-	-	48,687	48,687
Insurance contracts	-	-	-	3,507	3,507
Total assets	**$ 227,193**	**$ 713,457**	**$ -**	**$ 1,512,177**	**$ 2,452,827**
Pending transactions					**(111,173)**
Total net assets					**$ 2,341,654**
PBOP Assets:					
Investments					
Equity	$ 140,528	$ -	$ -	$ 224,383	$ 364,911
Diversified alternatives	33,367	-	-	32,954	66,321
Corporate bonds	-	2,895	-	-	2,895
Government securities	13,584	147,495	-	1,034	162,113
Insurance contracts	-	-	-	31,473	31,473
Total assets	**$ 187,479**	**$ 150,390**	**$ -**	**$ 289,844**	**$ 627,713**
Pending transactions					**1,362**
Total net assets					**$ 629,075**

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 includes 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 includes US agency and treasury securities, as well as state and local municipal bonds. The plans also include a small amount of Non-US government debt which is also captured here. US Government money market funds are also included. In addition, interest rate futures and swaps are held as a tool to manage interest rate risk.

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

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

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

Insurance contracts: Insurance contracts consists of Trust Owned Life Insurance.

Pending transactions: These are short term cash transactions that are expected to settle within a few days of the measurement date.

Defined Contribution Plan

NGUSA has defined contribution retirement plans that cover substantially all employees. For each of the years ended March 31, 2021, 2020, and 2019, the Company recognized an expense in the accompanying statement of income of $3.1 million for matching contributions.

10. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2021 are as follows:

(in thousands of dollars) March 31,	Maturities of Long-Term Debt
2022	$ 1,375
2023	13,875
2024	750
2025	750
2026	750
Thereafter	1,500,000
Total	$ 1,517,500

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. As of March 31, 2021 and 2020, the Company was in compliance with all such covenants.

Debt Authorizations

The Company had regulatory approval from the FERC to issue up to $400 million of short-term debt. The authorization was renewed with an effective date of January 11, 2021 and expires on October 14, 2022. The Company had no external short-term debt as of March 31, 2021 and 2020. Refer to Note 15, "Related Party Transactions" under "Intercompany Money Pool" for short-term debt outstanding with associated companies.

A new financing petition was filed with the RIPUC and approved on January 19, 2020 authorizing the issuance of up to $900 million of new long term debt through March 31, 2023. In April 2020, the Company issued $600 million of unsecured long-term debt at 3.395% with a maturity date of April 9, 2030, resulting in $300 million of remaining authorization.

First Mortgage Bonds

As of March 31, 2021, the Company had $17.5 million of FMB outstanding. Substantially all of the assets used in the gas business of the Company are subject to the lien of the mortgage indentures under which these FMB have been issued. The FMB have annual sinking fund requirements totaling approximately $1.4 million.

The Company has a maximum 70% of debt-to-capitalization covenant. Furthermore, if at any time the Company's debt exceeds 60% of the total capitalization, each holder of bonds then outstanding, shall receive effective as of the first date of such occurrence, a one time, and permanent, 0.20% increase in the interest rate paid by the Company on its bonds. As of March 31, 2021, and 2020, the Company was in compliance with this covenant.

Dividend Restrictions

Pursuant to the preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on payment of common stock dividends would come into effect if the common stock equity was, or by reason of payment of such dividends became, less than 25% of total capitalization. The Company was in compliance with this covenant and accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions as of March 31, 2021 or 2020.

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding where it can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock. A summary of cumulative preferred stock is as follows:

	Shares Outstanding		Amount		
	March 31,		March 31,		Call
Series	**2021**	2020	**2021**	2020	Price
	(in thousands of dollars, except per share and number of shares data)				
$50 par value -					
4.50% Series	**49,089**	49,089	**$ 2,454**	$ 2,454	$ 55.000

The Company did not redeem any preferred stock during the years ended March 31, 2021, 2020, or 2019. The annual dividend requirement for cumulative preferred stock was $0.1 million for the years ended March 31, 2021, 2020 and 2019.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,		
	2021	2020	2019
	(in thousands of dollars)		
Current federal income tax expense (benefit)	**$ 19,169**	$ 23,920	$ (12,398)
Deferred federal tax expense	**10,657**	2,976	36,415
Amortized investment tax credits (1)	**-**	(1)	(16)
Total deferred tax expense	**10,657**	2,975	36,399
Total income tax expense	**$ 29,826**	$ 26,895	$ 24,001

(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, 2021, 2020 and 2019 are 18.1%, 18.0% and 17.9%, respectively. The following table presents a reconciliation of income tax expense (benefit) at the federal statutory tax rate of 21% to the actual tax expense:

	Years Ended March 31,		
	2021	2020	2019
	(in thousands of dollars)		
Computed tax	**$ 34,608**	$ 31,353	$ 28,231
Change in computed taxes resulting from:			
Temporary differences flowed through	**(4,687)**	(4,655)	(4,293)
Other items, net	**(95)**	197	63
Total	**(4,782)**	(4,458)	(4,230)
Total income tax expense	**$ 29,826**	$ 26,895	$ 24,001

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

Deferred Tax Components

	March 31,	
	2021	**2020**
	(in thousands of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	$ 13,312	$ 9,091
Postretirement benefits and other employee benefits	10,821	29,126
Regulatory liabilities	91,251	89,216
Environmental remediation costs	23,485	25,096
Net operating losses	48,321	56,451
Other items – net	17,557	17,206
Total deferred tax assets	**204,747**	**226,186**
Deferred tax liabilities:		
Property related differences	438,025	420,471
Regulatory assets	110,015	128,530
Amortization of intangibles	47,872	44,119
Other items	1,057	384
Total deferred tax liabilities	**596,969**	**593,504**
Deferred income tax liabilities, net	**$ 392,222**	**$ 367,318**

Net Operating Losses

The amounts and expiration dates of the Company's net operating losses carryforwards as of March 31, 2021 are as follows:

Expiration of Net Operating Losses	Gross Carryforward Amount		Expiration Period
	(in thousands of dollars)		
Federal	**$**	**365,964**	**2033 – 2038**

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

Federal Income Tax Audit

During the year ended March 31, 2021, the Company reached a settlement with the IRS for the tax years ended March 31, 2013, March 31, 2014 and March 31, 2015. As a result of the settlement, the Company received a refund for tax and interest of $4.7 million.

During the year ended March 31, 2021, the IRS informed the Company that it does not intend to audit the Company's income tax returns for the periods ended March 31, 2016 and 2017 and commenced its examination of the next audit cycle which includes periods ended March 31, 2018 and 2019. While the income tax returns for fiscal years 2016 and 2017 are not currently being audited by the IRS, the statute of limitations for these tax periods does not expire until December 31, 2021. Therefore, the income tax returns for the years ended March 31, 2016 through March 31, 2021 remain subject to examination by the IRS.

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

Jurisdiction	Tax Year
Federal	March 31, 2016

The Company is not subject to state income tax due to the State of Rhode Island's exclusion of public utilities from income tax.

Uncertain Tax Positions

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other income, net, in the accompanying statements of income. As of both March 31, 2021 and 2020, the Company has accrued for interest related to unrecognized tax benefits of $0.3 million. During the years ended March 31, 2021, 2020 and 2019, the Company recorded interest expense of zero, zero, and $0.3 million, respectively. No tax penalties were recognized during the years ended March 31, 2021, 2020 or 2019.

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 such increases or decreases would be material to its results of operations, financial position, or cash flows.

12. ENVIRONMENTAL MATTERS

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

The United States Environmental Protection Agency ("EPA"), the Massachusetts Department of Environmental Protection ("DEP"), and the Rhode Island Department of Environmental Management ("DEM") have alleged that the Company is a potentially responsible party under state or federal law for the remediation of a number of sites at which hazardous waste is alleged to have been disposed. The Company's most significant liabilities relate to former Manufactured Gas Plant ("MGP") facilities formerly owned by the Blackstone Valley Gas and Electric Company and the Rhode Island gas distribution assets of New England Gas. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA, DEM and DEP. Expenditures incurred for the years ended March 31, 2021, 2020, and 2019 were $7.3 million, $1.9 million, and $1.8 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $111.8 million and $119.8 million as of March 31, 2021 and 2020, respectively. These costs are expected to be incurred over approximately 37 years, and these undiscounted amounts have been recorded as estimated liabilities on the balance sheet. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, the Company may seek additional recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The RIPUC has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Rhode Island. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability on the balance sheet. Rate-recoverable contributions of approximately $3.1 million are added annually to the fund, along with interest and any recoveries from insurance carriers and other third-parties. Accordingly, as of March 31, 2021 and 2020, the Company has recorded environmental regulatory assets of $110.0 million and $119.0 million, respectively, and environmental regulatory liabilities of $16.2 million and $18.8 million, respectively (See Note 4, "Regulatory Assets and Liabilities" for additional details).

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

13. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company has several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. Additionally, the Company has 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 is liable for these payments regardless of the level of service required from third-parties.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2021 are summarized in the table below:

(in thousands of dollars) March 31,	Energy Purchases
2022	$ 266,493
2023	104,693
2024	50,583
2025	47,598
2026	39,870
Thereafter	349,765
Total	$ 859,002

Long-term Contracts for Renewable Energy

Deepwater Agreement

The 2009 Rhode Island law required the Company to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, the Company entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC ("Deepwater"), which was approved by the RIPUC in August 2010. The wind turbines reached commercial operation on December 12, 2016 and the PPA is being accounted for as a capital lease. The Company also negotiated a Transmission Facilities Purchase Agreement ("Facilities Purchase Agreement," or "FPA") with Deepwater to purchase the permits, engineering, real estate, and other site development work for construction of the undersea transmission cable (collectively, the "Transmission Facilities"). On April 2, 2014, the Division issued its Consent Decision for the Company to execute the FPA with Deepwater. In July 2014, four agreements were filed with the FERC, in part, for approval to recover the costs associated with the transmission cable and related facilities (the "Project") that will be allocated to the Company and Block Island Power Company through transmission rates. On September 2, 2014, the FERC accepted all four agreements thus approving cost recovery for the Project, with no conditions, that will apply to the Company's costs, as well as those of NEP. The agreements went into effect on September 30, 2014. On January 30, 2015, the Company closed on its purchase of the Transmission Facilities from Deepwater. The Company placed the Transmission Facilities into service on October 31, 2016.

Three-State Procurement

On April 9, 2018, the RIPUC approved eight long-term (20-year) contracts for the purchase of the electricity and renewable energy credits from eight separate generating facilities pursuant to the Rhode Island Long-Term Contracting Standard. The Company will purchase the actual output generated by the individual facilities, which in aggregate represents approximately 39 MWs of nameplate capacity. Because the contracts were approved pursuant to the Rhode Island Long-Term Contracting Standard, the Company may collect 2.75% remuneration on the annual payments made under the contracts. The contracts resulted from a three-state solicitation for renewable energy generation proposals.

Offshore Wind Energy Procurement

On December 6, 2018, the Narragansett Electric Company entered into a 20-year PPA with DWW Rev I, LLC ("Revolution Wind"), for the purchase of the electricity and renewable energy credits generated by the offshore windfarm proposed by Revolution Wind, that will have a capacity of up to 408 MW. The anticipated commercial operations date for the windfarm is in January 2024. On May 28, 2019, at an open meeting, the RIPUC approved the contract without remuneration. The written order approving the agreement and that Company will be able to recover the cost incurred under the agreement was issued by the RIPUC on June 7, 2019.

Annual Solicitations

The 2009 Rhode Island law (Long Term Contracting Standard ("LTCS")) also requires that, beginning on July 1, 2010, the Company conduct four annual solicitations for proposals from renewable energy developers and, provided commercially reasonable proposals have been received, enter into long-term contracts for the purchase of capacity, energy, and attributes from newly developed renewable energy resources. The Company's four solicitations have resulted in four PPAs that have been approved by the RIPUC:

- First Solicitation: On July 28, 2011, the RIPUC approved a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project located in Johnston, Rhode Island. The facility reached commercial operation on August 24, 2017.
- Second Solicitation: On May 11, 2012, the RIPUC approved a 15-year PPA with Black Bear Development Holdings, LLC for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. The facility reached commercial operation on November 22, 2013.
- Third Solicitation: On October 25, 2013, the RIPUC approved a 15-year PPA with Champlain Wind, LLC for a 48 MW land-based wind project located in Carroll Plantation and Kossuth Township, Maine. The PPA was terminated on January 23, 2017 because one of the required permits for the project was rejected. The impact of this termination is that the Company then needed to backfill the MW capacity from that project to meet the 90 MW minimum long-term capacity requirements under the state statute, that it fulfilled in the fifth solicitation.
- Fourth Solicitation: On October 29, 2015, the RIPUC approved a 15-year PPA with Copenhagen Wind Farm, LLC for an 80 MW land-based wind project located in Denmark, New York. The facility reached commercial operation on December 27, 2018.

In 2014 the LTCS was amended to allow for additional solicitations until the 90 MW contracting capacity requirement was met.

- Fifth Solicitation: On May 11, 2020, the RIPUC approved a 20 year PPA with Gravel Pit Solar II, LLC for a 49.5 MW land based bifacial solar project located in East Windsor, CT. The anticipated commercial operation date is March 31, 2023.

As approved by the RIPUC, the Company is allowed to pass through commodity-related / purchased power costs to customers and collect remuneration equal to 2.75%.

Aquidneck Island

On January 21, 2019, we suffered a significant loss of gas supply to the distribution system that serves our customers on Aquidneck Island in Rhode Island. As a result, we made the decision to interrupt the gas service to the Aquidneck Island system to protect the safety of our customers and the public. Overall, approximately 7,500 customers lost their gas service. On October 30, 2019, the RI Division issued their Summary Investigation Report regarding the gas service interruption. In the report, the Division identified the causes of the outages, which included multiple factors, some of which were outside the control of the Company. The Division's Report also recommended several gas system improvements, many of which we have addressed already. On December 13, 2019, we filed our response to the Division's Report and continue to meet with the Division on a quarterly basis regarding winter reliability issues for Aquidneck Island and Rhode Island. On September 23, 2020, we published a long-term capacity study for energy solutions for Aquidneck Island for stakeholder feedback. We are gathering stakeholder feedback on a hybrid model approach that will offset gas demand growth with advanced non-infrastructure solutions while addressing existing gas capacity and vulnerability challenges with an alternate LNG solution. On May 18, 2021, we attended an informational session at the Rhode Island Public Utilities Commission to update the Commission on the Company's long-term capacity solutions for Aquidneck Island.

In November 2019, the Company was first served with an amended class action complaint on behalf of business owners on Aquidneck and a separate class action on behalf of individuals in the affected areas. Further amendments to the complaints have subsequently been filed. The Company is actively defending against these class action complaints. Additionally, six subrogation actions allegedly related to event have been filed against the Company to date.

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.

New York Public Service Commission Investigation

On June 17, 2021, five former NGUSA employees in the downstate New York facilities department were arrested on federal charges alleging fraud and bribery. It is NGUSA's understanding that the investigation by the US Attorney's Office and FBI remains ongoing; NGUSA is a victim of the alleged crimes and will continue to comply with the government's investigation. The New York Public Service Commission, the Massachusetts Department of Public Utilities, and the Rhode Island Public Utilities Commission have each issued requests for information related to the alleged criminal conduct. At this time, it is not possible to predict the outcome of the regulatory review or determine the amount, if any, of any potential liabilities that may be incurred by the Company related to this matter. However, the Company does not expect this matter will have a material adverse effect on its results of operations, financial position or cash flows.

Energy Efficiency Programs Investigation

NGUSA is performing an internal investigation regarding conduct associated with the Company's energy efficiency programs. 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. However, the Company does not expect this matter will have a material adverse effect on its results of operations, financial position or cash flows.

14. LEASES

The Company has no finance leases as of March 31, 2021 or 2020. The Company has various operating leases, primarily related to a transmission line, buildings, land, and fleet vehicles used to support the electric and gas operations, with lease terms ranging between 4 and 50 years. The expense related to operating leases was $8.0 million and $7.9 million for the years ended March 31, 2021 and 2020, respectively.

Certain building leases provide the Company with an option to extend the lease term. The Company has included the periods covered by the extension options in its determination of the lease term when management believes it is reasonably certain the Company will exercise its option.

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. The variable lease payments were not material for the year ended March 31, 2021.

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. Operating lease ROU assets are included in property, plant and equipment, net, and operating lease liabilities are included in other current liabilities and other noncurrent liabilities on the balance sheet.

As of March 31, 2021, 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 and other operating lease-related information:

	Year ended March 31,	
	2021	**2020**
(in thousands of dollars)		
Cash paid for amounts included in lease liabilities		
Operating cash flows from operating leases	**$ 8,006**	$ 7,889
ROU assets obtained in exchange for new operating lease liabilities	**$ 6,108**	$ 2,644
Weighted-average remaining lease term – operating leases	**5**	4
Weighted-average discount rate – operating leases	**2.53%**	2.65%

The following contains the Company's maturity analysis of its operating lease liabilities as of March 31, 2021, showing the undiscounted cash flows on an annual basis reconciled to the undiscounted cash flows of the operating lease liabilities recognized in the comparative balance sheet:

	Operating Leases
Year Ending March 31,	*(in thousands of dollars)*
2022	**$ 6,662**
2023	**5,436**
2024	**3,945**
2025	**2,127**
2026	**1,446**
Thereafter	**2,457**
Total future minimum lease payments	**$ 22,073**
Less: imputed interest	**(1,203)**
Total	**$ 20,870**
Reported as of March 31, 2021:	
Current lease liability	**$ 6,210**
Non-current lease liability	**14,660**
Total	**$ 20,870**

There are certain leases in which the Company is the lessor. Revenue under such leases was immaterial for the years ended March 31, 2021 and 2020.

15. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

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

The Company records short-term receivables 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 Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2021	2020	**2021**	2020
	(in thousands of dollars)			
New England Power Company	**$ 13,803**	$ 12,872	**$ 27,764**	$ 25,937
NGUSA Service Company	**3,498**	4,571	**29,423**	24,754
Other	**85**	2,231	**3,200**	3,740
Total	**$ 17,386**	$ 19,674	**$ 60,387**	$ 54,431

As discussed in Note 5 "Rate Matters," NEP operates the pooled transmission facilities of MECO, the Company, and NEP as a single integrated system ("NEPOOL") under NEP's Tariff No. 1. These transmission services are regulated by both ISO-NE and by the FERC. NEP charges ISO-NE for these transmission services. As NEP is the sole operator of NEPOOL assets, ISO-NE revenues are remitted from NEP to the Company representing the substantial portion of the affiliated accounts receivable due from NEP.

In turn, ISO-NE charges the Company for regional network services ("RNS") with some of those charges being associated with the Company-owned transmission assets in the NEPOOL. As of March 31, 2021 and March 31, 2020, $18.6 million and $17.2 million of the unpaid charges from ISO-NE to the Company have been presented as an affiliated payable to NEP related to these Company-owned transmission assets, respectively. Additionally, NEP also charges the Company local network service ("LNS") rates. Amounts paid to NEP for LNS for the years ended March 31, 2021, 2020 and 2019 were $52.7 million, $57.4 million, and $46.5 million, respectively. These amounts are presented within operations and maintenance expense within the accompanying statements of income.

Advances from Affiliates

Since December 2008, the Company had FERC and board authorization to borrow up to $250 million as deemed necessary for working capital needs. The advance is non-interest bearing. As of March 31, 2021 and 2020, the Company had no outstanding advances from affiliates.

Intercompany Money Pool

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

The Regulated Money Pool is funded by operating funds from participants. NGUSA has the ability to borrow up to $3.0 billion from National Grid plc for working capital needs including funding of the Regulated Money Pool, if necessary. The Company had short-term intercompany money pool investments of $158.6 million and borrowings of $351.4 million as of March 31, 2021 and 2020, respectively. The average interest rates for the intercompany money pool were 0.7%, 2.4%, and 2.4% for the years ended March 31, 2021, 2020, and 2019, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at cost without a markup. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, and total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator determined using a 3-point formula based on net margin, net property, plant and equipment, and operations and maintenance expense.

Charges from the service companies of NGUSA to the Company are mostly related to traditional administrative support functions, of which for the years ended March 31, 2021, 2020, and 2019 were $270.6 million, $250.8 million, and $229.7 million, respectively.