Boston Gas Company
d/b/a National Grid

Financial Statements

For the years ended March 31, 2019, 2018, and 2017

BOSTON GAS COMPANY

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Boston Gas Company

We have audited the accompanying financial statements of Boston Gas Company d/b/a National Grid (the "Company"), which comprise the balance sheets and statements of capitalization as of March 31, 2019 and 2018 and the related statements of operations, cash flows, and changes in shareholder's equity for the two years in the period ended March 31, 2019, 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 Boston Gas Company d/b/a National Grid as of March 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Predecessor Auditors' Opinion on 2017 Financial Statements

The financial statements of the Company as of and for the year ended March 31, 2017, were audited by other auditors whose report, dated July 21, 2017, expressed an unmodified opinion on those statements.

Deloitte & Touche LLP

July 2, 2019

BOSTON GAS COMPANY
STATEMENTS OF OPERATIONS
(in thousands of dollars)

	Years Ended March 31,		
	2019	2018	2017
Operating revenues:	**$ 1,341,679**	$ 1,251,739	$ 1,066,378
Operating expenses:			
Purchased gas	**497,517**	484,267	349,144
Operations and maintenance	**744,324**	394,504	371,801
Depreciation	**162,005**	160,312	148,941
Other taxes	**65,622**	59,970	55,210
Total operating expenses	**1,469,468**	1,099,053	925,096
Operating (loss) income	**(127,789)**	152,686	141,282
Other income and (deductions):			
Interest on long-term debt	**(46,082)**	(41,587)	(31,479)
Other interest, including affiliate interest	**6,650**	(1,067)	5,407
Other (deductions) income, net	**(6,994)**	6,798	(6,609)
Total other deductions, net	**(46,426)**	(35,856)	(32,681)
(Loss) income before income taxes	**(174,215)**	116,830	108,601
Income tax (benefit) expense	**(47,214)**	42,896	43,998
Net (loss) income	**$ (127,001)**	$ 73,934	$ 64,603

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

BOSTON GAS COMPANY
STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(in thousands of dollars)

	Year Ended March 31,
	2017*
Net (loss) income	$ 64,603
Other comprehensive (loss) income, net of taxes:	
Unrealized (losses) gains on securities	5
Total other comprehensive (loss) income	5
Comprehensive (loss) income	$ 64,608
Related tax benefit (expense):	
Unrealized losses (gains) on securities	$ (3)
Total tax benefit (expense)	$ (3)

*2018 and 2019 not presented due to immaterial nature of statement

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

BOSTON GAS COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31,		
	2019	2018	2017
Operating activities:			
Net (loss) income	$ (127,001)	$ 73,934	$ 64,603
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation	162,005	160,312	148,941
Deferred income tax	7,386	48,436	36,815
Bad debt expense	27,989	17,750	20,564
Pension and postretirement benefits expenses, net	4,113	25,638	25,550
Pension and postretirement benefits contributions	(18,239)	(21,896)	(22,316)
Environmental remediation payments	(675)	(1,688)	(6,268)
Changes in operating assets and liabilities:			
Accounts receivable, net, and unbilled revenues	(17,071)	(103,719)	(81,804)
Accounts receivable from/payable to affiliates, net	14,088	-	-
Inventory	(764)	(1,377)	9,926
Regulatory assets and liabilities, net	50,728	(7,119)	14,314
Derivative instruments	5,301	(5,340)	(2,772)
Prepaid and accrued taxes	(81,392)	2,290	(8,350)
Accounts payable and other liabilities	58,275	17,116	15,599
Other, net	(20)	(4,699)	(1,571)
Net cash provided by operating activities	84,723	199,638	213,231
Investing activities:			
Capital expenditures	(275,643)	(495,594)	(424,457)
Cost of removal	(27,645)	(36,784)	(31,950)
Net cash used in investing activities	(303,288)	(532,378)	(456,407)
Financing activities:			
Payments on long-term debt	(20,000)	(8,000)	(10,000)
Issuance of long-term debt	-	499,561	-
Payment of debt issuance costs	-	(2,000)	-
Intercompany money pool	246,866	(429,167)	253,733
Equity infusion from Parent	-	270,000	-
Net cash provided by financing activities	226,866	330,394	243,733
Net increase (decrease) in cash and cash equivalents	8,301	(2,346)	557
Cash and cash equivalents, beginning of year	3,109	5,455	4,898
Cash and cash equivalents, end of year	$ 11,410	$ 3,109	$ 5,455
Supplemental disclosures:			
Interest paid	$ (51,225)	$ (43,120)	$ (31,558)
Income taxes refunded	14,673	11,427	202
Significant non-cash items:			
Capital-related accruals included in accounts payable	18,625	19,064	26,253

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

BOSTON GAS COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2019	2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,410	$ 3,109
Accounts receivable	335,016	329,062
Allowance for doubtful accounts	(56,604)	(47,159)
Accounts receivable from affiliates	9,722	8,928
Unbilled revenues	74,978	82,405
Inventory	49,781	49,017
Regulatory assets	103,491	125,443
Accrued tax benefit	83,143	5,350
Other	3,831	11,109
Total current assets	614,768	567,264
Property, plant, and equipment, net	3,684,546	3,493,316
Other non-current assets:		
Regulatory assets	141,169	114,236
Goodwill	396,322	396,322
Postretirement benefits assets	33,284	35,136
Other	549	612
Total other non-current assets	571,324	546,306
Total assets	$ 4,870,638	$ 4,606,886

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

BOSTON GAS COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2019	2018
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 80,029**	$ 62,755
Accounts payable to affiliates	**86,952**	28,889
Current portion of long-term debt	**7,000**	20,000
Interest accrued	**8,837**	9,597
Regulatory liabilities	**82,878**	47,950
Intercompany money pool	**371,154**	167,469
Payroll and benefits accruals	**14,771**	15,578
Other	**9,272**	11,051
Total current liabilities	**660,893**	363,289
Other non-current liabilities:		
Regulatory liabilities	**952,112**	906,414
Asset retirement obligations	**15,975**	14,949
Deferred income tax liabilities, net	**315,778**	307,966
Postretirement benefits	**77,932**	69,616
Environmental remediation costs	**37,750**	39,089
Other	**89,399**	51,302
Total other non-current liabilities	**1,488,946**	1,389,336
Commitments and contingencies (Note 12)		
Capitalization:		
Shareholder's equity	**1,650,885**	1,777,888
Long-term debt	**1,069,914**	1,076,373
Total capitalization	**2,720,799**	2,854,261
Total liabilities and capitalization	**$ 4,870,638**	$ 4,606,886

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

BOSTON GAS COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

			March 31, 2019	March 31, 2018
Total shareholder's equity			$ 1,650,885	$ 1,777,888
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Note	4.49%	February 15, 2042	500,000	500,000
Senior Note	3.15%	August 1, 2027	500,000	500,000
			1,000,000	1,000,000
Medium-Term Notes ("MTNs")				
MTN Series 1992 A	8.33%	July 10, 2018	-	10,000
MTN Series 1994 B	6.93%	January 15, 2019	-	10,000
MTN Series 1989 A	8.97%	December 15, 2019	7,000	7,000
MTN Series 1990 A	9.75%	December 1, 2020	5,000	5,000
MTN Series 1990 A	9.05%	September 1, 2021	15,000	15,000
MTN Series 1992 A	8.33%	July 5, 2022	10,000	10,000
MTN Series 1995 C	6.95%	December 1, 2023	10,000	10,000
MTN Series 1994 B	6.98%	January 15, 2024	6,000	6,000
MTN Series 1995 C	6.95%	December 1, 2024	5,000	5,000
MTN Series 1995 C	7.25%	October 1, 2025	20,000	20,000
MTN Series 1995 C	7.25%	October 1, 2025	5,000	5,000
			83,000	103,000
Total debt			1,083,000	1,103,000
Unamortized debt discount			(392)	(439)
Unamortized debt issuance costs			(5,694)	(6,188)
Current portion of long-term debt			(7,000)	(20,000)
Long-term debt			1,069,914	1,076,373
Total capitalization			$ 2,720,799	$ 2,854,261

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

BOSTON GAS COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(in thousands of dollars)

	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Unrealized Gain (Loss) on Available-For-Sale Securities	Accumulated Other Comprehensive Income (Loss): Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2016	**$ 51,418**	**$ 975,444**	**$ 67**	**$ 67**	**$ 342,420**	**$ 1,369,349**
Net income	-	-	-	-	64,603	64,603
Other comprehensive income:						
Unrealized gains on securities, net of $3 tax expense	-	-	5	5	-	5
Total comprehensive income						64,608
Balance as of March 31, 2017	**$ 51,418**	**$ 975,444**	**$ 72**	**$ 72**	**$ 407,023**	**$ 1,433,957**
Net income	-	-	-	-	73,934	73,934
Other comprehensive loss:						
Unrealized losses on securities, net of $1 tax benefit	-	-	(3)	(3)	-	(3)
Total comprehensive income						73,931
Equity infusion from Parent	-	270,000	-	-	-	270,000
Balance as of March 31, 2018	**$ 51,418**	**$ 1,245,444**	**$ 69**	**$ 69**	**$ 480,957**	**$ 1,777,888**
Net loss	-	-	-	-	(127,001)	(127,001)
Other comprehensive loss:						
Unrealized losses on securities, net of $1 tax benefit	-	-	(2)	(2)	-	(2)
Total comprehensive loss						(127,003)
Impact of adoption of the recognition and measurement of financial assets and liabilities standard	-	-	(69)	(69)	69	-
Balance as of March 31, 2019	**$ 51,418**	**$ 1,245,444**	**$ (2)**	**$ (2)**	**$ 354,025**	**$ 1,650,885**

The Company had 514,184 shares of common stock authorized, issued, and outstanding, with a par value of $100 per share at March 31, 2019 and 2018.

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

BOSTON GAS COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Boston Gas Company d/b/a National Grid ("the Company") is a gas distribution company engaged in the transportation and sale of natural gas to approximately 712,000 residential, commercial, and industrial customers in the City of Boston, Essex County, and other communities in eastern and central Massachusetts.

Prior to April 30, 2018, the Company was an indirect subsidiary of KeySpan Corporation ("KeySpan"), which was 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. Effective April 30, 2018, KeySpan merged into NGUSA, and, from that point forward, the Company is an indirect subsidiary of NGUSA.

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

The Company has evaluated subsequent events and transactions through July 2, 2019, 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, 2019.

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. Actual results could differ from those estimates.

Regulatory Accounting

The Massachusetts Department of Public Utilities ("DPU") regulates the rates the Company charges its customers. In certain cases, the rate actions of the DPU 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 gas distribution services provided on a monthly billing cycle basis. The Company records unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period (See Note 4, "Revenue," for additional details).

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. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues).

Income Taxes

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

The effects of tax positions are recognized in the 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 benefits 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 those subsidiaries 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.

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 $28.0 million, $17.8 million, and $20.6 million for the years ended March 31, 2019, 2018, and 2017, respectively, within operations and maintenance in the statements of operations.

Inventory

Inventory is comprised of materials and supplies, as well as gas in storage. Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. There were no significant write-offs of obsolete inventory for the years ended March 31, 2019, 2018, or 2017.

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 DPU.

The Company had materials and supplies of $13.4 million and $15.8 million and gas in storage of $36.4 million and $33.2 million at March 31, 2019 and 2018, respectively.

Derivative Instruments

The Company uses derivative instruments to manage commodity price risk. All derivative instruments 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 gas cost 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 operations and then refunded to, or collected from, customers consistent with regulatory requirements.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, but rather to record and present the fair value of the derivative instruments on a gross basis, with related cash collateral recorded within restricted cash and special deposits on the balance sheet. There was no related cash collateral as of March 31, 2019 or 2018.

Natural Gas Long-Term Arrangements

The Company enters into long-term gas contracts to procure gas to serve its customers. Those contracts include Asset Management Agreements, Baseload, and Peaking gas contracts. The Company evaluates whether such agreements are leases, derivative instruments, or executory contracts, under the guidance for Variable Interest Entities included in Topic 810, "Consolidations," and applies the appropriate accounting treatment.

Fair Value Measurements

The Company measures derivative instruments, available-for-sale 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; and
- 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.
- Not categorized: certain investments are not 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, derived from the underlying securities' quoted prices in active markets.

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 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. 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").

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 DPU. The average composite rates for the years ended March 31, 2019, 2018, and 2017 are as follows:

	Years Ended March 31,		
	2019	2018	2017
Composite rates	**4.1%**	4.4%	3.9%

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 $689.4 million and $644.8 million at March 31, 2019 and 2018, 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 operations as non-cash income in other (deductions) 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 rate base. The Company recorded AFUDC related to equity of $3.6 million and $3.1 million for the years ended March 31, 2019 and 2018, respectively, and had no AFUDC related to equity for the year ended March 31, 2017. The Company recorded AFUDC related to debt of $4.1 million, $2.9 million, and $1.0 million for the years ended March 31, 2019, 2018, and 2017, respectively. The average AFUDC rates for the years ended March 31, 2019, 2018, and 2017 were 3.9%, 3.1%, and 1.0%, 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 may not be recoverable. 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, 2019, 2018, and 2017, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on January 1, and when events occur or circumstances change that would more likely than not reduce the fair value of the Company 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 required under the current standard. The one-step approach 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.

Historically, the fair value of the Company was calculated for the annual goodwill impairment test utilizing both the income and market-based approaches. For the year ended March 31, 2019, the fair value of the Company was calculated utilizing only the income approach. The Company believes that this approach provides the most reliable information about the Company's estimated fair value. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2019. There were also no impairment charges recorded for the years ended March 31, 2018 or 2017.

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant, and equipment, primarily associated with the Company's gas distribution facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, if the fair value can be reasonably estimated. In the period in which new asset retirement obligations, or changes to the timing or amount of existing retirement obligations, are recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the asset retirement obligation is accreted to its present value. The Company applies regulatory accounting guidance, and both the depreciation and accretion costs associated with asset retirement obligations are recorded as increases to regulatory assets on the balance sheets. These regulatory assets represent timing differences between the recognition of costs in accordance with U.S. GAAP and costs recovered through the ratemaking process.

The following table represents the changes in the Company's asset retirement obligations:

	Years Ended March 31,	
	2019	2018
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ 15,812**	$ 15,012
Accretion expense	**1,079**	1,024
Liabilities settled	**(140)**	(224)
Balance as of the end of the year	**$ 16,751**	$ 15,812

The Company had a current portion of asset retirement obligations of $0.8 million and $0.9 million included in other current liabilities on the balance sheets at March 31, 2019 and 2018, respectively.

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 the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2019

Pension and Postretirement Benefits

In March 2017, the Financial Accounting Standards Board ("FASB") issued ASU No. 2017-07, "Compensation Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost," which changes certain presentation and disclosure requirements for employers that sponsor defined benefit pension and other postretirement benefit plans. The ASU requires the service cost component of the net benefit cost to be classified within the same line item as other compensation in operating (loss) income in an entity's statements of operations and the other components of net benefit cost to be classified outside of operating (loss) income on a retrospective basis. In addition, as prescribed by the ASU, only the service cost component will be eligible for capitalization when applicable, on a prospective basis.

The Company adopted this new guidance on April 1, 2018. Although required by the standard, the Company elected not to retrospectively adjust the accompanying 2018 and 2017 financial statements, as management determined that such retrospective application is not material to the Company's statements of operations for the years ended March 31, 2018 and 2017 presented herein. The adoption of this ASU did not have a material effect on the Company's results of operations, cash flows, and financial position.

Statement of Cash Flows

In August 2016, the FASB issued ASU No. 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments," which provides guidance about the classification of certain cash receipts and payments within the statement of cash flows, including debt prepayment or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and policies, and distributions received from equity method investments. The Company adopted the new guidance in the current fiscal year and applied it retrospectively for each prior period presented. The application of the new guidance did not have a material impact on the Company's presentation of its statement of cash flows.

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." The FASB further amended ASC 606, "Revenue from Contracts with Customers," through various updates issued thereafter. The underlying principle of this ASU is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to, in exchange for those goods or services. The Company adopted the new guidance on April 1, 2018 using the modified retrospective method applied to contracts that were not completed as of April 1, 2018, and the Company did not recognize an adjustment to retained earnings for the cumulative effect of adopting the standard.

The adoption of ASC 606, "Revenue from Contracts with Customers," did not have a material impact on the presentation of the Company's results of operations, cash flows, or financial position. The Company has added additional disclosures as required under ASC 606, "Revenue from Contracts with Customers" (See Note 4, "Revenue," for additional details).

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU No. 2016-01, "Financial Instruments–Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities." The new guidance eliminates the available-for-sale and cost method classification for equity securities and requires that all equity investments, other than those accounted for using the equity method of accounting, be measured and recorded at fair value, with any changes in fair value recognized through net (loss) income. However, for equity investments that do not have a readily determinable fair value, an entity may choose to measure equity investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for identical or similar investments. If any entity elects to use the measurement alternative for equity investments without readily determinable fair values, those investments must be qualitatively assessed for impairment at each reporting period, and, if impairment exists, the investment is required to be measured at fair value. The guidance does not impact the classification or measurement of investments in debt securities. The guidance also amended certain disclosure requirements related to financial instruments. The Company adopted the guidance on April 1, 2018 using a modified retrospective transition approach, with a cumulative effect adjustment to retained earnings, which was reclassified from accumulated other comprehensive income (loss), for $0.1 million related to equity investments that were previously classified as available-for-sale.

Accounting Guidance Not Yet Adopted

Leases

In February 2016, the FASB issued ASU No. 2016-02, "Leases" (Topic 842), related to lease accounting. For the Company, the new standard is effective for the fiscal year ending March 31, 2020, and interim periods within. Under the new standard, a lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified assets for a period of time in exchange for consideration. Under the requirements of the new standard, lessees will need to recognize leases on the balance sheet as a right-of-use asset and a related lease liability, which will be equal to the present value of the estimated future lease payments. The right-of-use asset at inception will be based on the liability, subject to certain adjustments, such as initial direct costs. The new standard requires leases to be classified as either operating or financing, which will impact the amount and classification of lease-related expenses on the statements of operations. Under the new standard, lessor accounting is largely unchanged. The new standard also has additional disclosure requirements.

The new standard provides the Company with transition practical expedients, including a package of three expedients that must be taken together and allows the Company to: not reassess whether existing contracts contain leases, carry forward the existing classification of any leases, and not reassess initial direct costs associated with existing leases. The Company has exercised its option to elect the package of practical expedients. The Company will make the election under the new standard to not reflect a right-of-use asset or related liability for leases with a term of 12 months or less. The Company has also elected the practical expedient to not reevaluate land easements existing at adoption if they were not previously accounted for as leases. The Company will not make the election to combine the lease components and the associated non-lease components of an arrangement and account for this as a single lease component, and will also not elect the expedient to use hindsight in determining the lease term for existing leases at the time of adoption.

The Company will recognize and measure the cumulative effect of the new standard at the beginning of the earliest period presented using the modified retrospective approach. The Company determined the impact the ASU will have on its financial statements by reviewing its lease population and identifying lease data needed for the disclosure requirements. The Company has various operating leases relating to office space. The Company will implement a new lease accounting system in fiscal year 2020 to ensure ongoing compliance with the ASU's requirements. The Company recognized approximately $55.6 million of operating lease liabilities as right-of-use assets on the balance sheets upon transition at April 1, 2019. The implementation of the new guidance will not materially impact the Company's results of operations or cash flows, as the Company does not expect significant changes to its pattern of expense recognition as a result of the new standard. The Company's operating leases are further discussed in Note 12, "Commitments and Contingencies".

Financial Instruments

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 FASB further amended Topic 326 through additional updates issued thereafter. 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. For the Company, the requirements of the new standard will be effective for the fiscal year ending March 31, 2022, and interim periods within, with early adoption permitted from the fiscal year ending March 31, 2020 and interim periods within. The Company is currently assessing the impact of this standard.

Reclassifications

Certain reclassifications have been made to the prior years' financial statements to conform the prior years' data to the current year's presentation. These reclassifications had no effect on reported income, total assets, or shareholder's equity, as previously reported.

3. WORK CONTINUATION PLAN

On June 25, 2018, the Company and its affiliate, Colonial Gas Company ("Colonial Gas"), activated a work continuation plan after contractual agreements with two of their United Steelworkers unions expired and new agreements could not be reached. The United Steelworkers unions disagreed with proposed changes to employee health and retirement benefits. While the work continuation plan was in effect, internal management employees supplemented by external contractors filled the roles normally staffed by the United Steelworkers unions. As a result, the Company incurred approximately $366 million of costs, which are reflected in operations and maintenance expense in the statements of operations for the year ended March 31, 2019. The Company and Colonial Gas reached new contractual agreements with two of their United Steelworkers unions, which were ratified on January 7, 2019.

4. REVENUE

The following table presents, for the year ending March 31, 2019, revenue from contracts with customers, as well as additional revenue from sources other than contracts with customers, disaggregated by major source:

	Year Ended March 31, 2019	
	(in thousands of dollars)	
Revenue from Contracts with Customers:		
Gas Distribution	$	1,317,823
Other Revenue from Contracts with Customers		72,352
Total Revenue from Contracts with Customers		1,390,175
Revenue from Regulatory Mechanisms		(48,496)
Total Operating Revenues	$	1,341,679

Gas Distribution: The Company owns, maintains, and operates a natural gas distribution network serving areas in Massachusetts. Distribution revenues are primarily from the sale of gas and related services to retail customers. Distribution sales are regulated by the DPU, which is responsible for determining the prices and other terms of services as part of the ratemaking process. The arrangement where a utility provides a service to a customer in exchange for a price approved by a regulator is referred to as a tariff sales contract. Gas distribution revenues are derived from the regulated sale and distribution of 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 the products and services provided, along with a return on investment.

The performance obligation related to distribution sales is to provide natural gas to the customers on demand. The natural gas supplied under the tariff represents a single performance obligation, as it is a series of distinct goods or services that are substantially the same. The performance obligation is satisfied over time because the customer simultaneously receives and consumes the natural gas as the Company provides this service. 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 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 natural gas from other suppliers. In those circumstances, revenue is only recognized for providing delivery of the commodity to the customer.

Other Revenue from Contracts with Customers: Other Revenue from Contracts with Customers consists of off-system sales, which represent direct sales of gas to participants in the wholesale natural gas marketplace, which occur after customers' demands are satisfied.

Revenue from Regulatory Mechanisms: The Company records revenues in accordance with accounting principles for rate-regulated operations that are 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 programs that qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the Company to adjust rates in the future, in response to past activities or completed events. The Company's gas distribution rates have a Revenue Decoupling Mechanism ("RDM"), which allows for semi-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 ratemaking 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 and the amounts are determinable and probable of recovery (or payment) through future rate adjustments.

5. REGULATORY ASSETS AND LIABILITIES

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

		March 31,	
		2019	2018
		(in thousands of dollars)	
Regulatory assets			
Current:			
	Gas costs adjustment	**$ 101,964**	$ 106,256
	Rate adjustment mechanisms	**-**	12,568
	Other	**1,527**	6,619
	Total	**103,491**	125,443
Non-current:			
	Asset retirement obligation	**11,970**	10,885
	Capital tracker	**4,452**	22,181
	Environmental response costs	**54,412**	58,842
	Gas business enablement	**7,339**	-
	Postretirement benefits	**40,954**	21,561
	Rate adjustment mechanisms	**19,951**	-
	Other	**2,091**	767
	Total	**141,169**	114,236
Regulatory liabilities			
Current:			
	Derivative instruments	**-**	3,774
	Local distribution adjustment clause	**24,270**	-
	Profit sharing	**23,616**	21,672
	Revenue decoupling mechanism	**34,346**	22,504
	Other	**646**	-
	Total	**82,878**	47,950
Non-current:			
	Cost of removal	**689,398**	644,789
	Regulatory tax liability, net	**255,420**	255,847
	Other	**7,294**	5,778
	Total	**952,112**	906,414
	Net regulatory liabilities	**$ (790,330)**	$ (714,685)

Asset retirement obligation: Represents accretion expense deferred as part of the Company's asset retirement obligation and is recovered through rates as part of depreciation expense.

Capital tracker: The Company has in place a Gas System Enhancement Plan ("GSEP"), which was approved by the DPU on April 30, 2015 and is designed to provide concurrent recovery of the revenue requirement associated with the Company's capital costs for the replacement of eligible leak-prone pipe and ancillary equipment pursuant to the 2014 Gas Leaks Act passed in Massachusetts.

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.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at former manufactured gas plant ("MGP") sites and related facilities. The Company's rate plans provide for the recovery of previously-incurred costs over a seven-year recovery period. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

Gas business enablement: The regulatory asset represents costs in excess of those in base rates incurred to implement the Gas Business Enablement program. This program will consolidate and modernize the Company's systems and operating platforms to facilitate internal efficiencies and improve customers' experience, which was approved by the DPU on September 28, 2018.

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 actual revenues and the underlying cost being recovered, as approved by the DPU. These amounts will be refunded to, or recovered from, customers over the next year.

Local distribution adjustment clause ("LDAC"): A mechanism by which the Company is required to adjust its rates annually to recover or refund sundry costs, including the capital tracker, energy efficiency expenditures, pension and PBOP costs, residential assistance costs, service quality penalties, and miscellaneous other amounts due to or from customers through rates.

Postretirement benefits: The regulatory asset represents the Company's 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 passed back in future periods.

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

Rate adjustment mechanisms: Active Hardship-Protected Accounts Receivable is a mechanism which, through rates, allows the Company to recover account balances related to customers that are protected from service cutoff for non-payment with balances over 360 days past-due. The balance in this account represents the deferral of the Company's hardship balance.

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

Revenue decoupling mechanism ("RDM")*:* As approved by the DPU, the Company has a gas RDM, which allows for seasonal (peak/off-peak) adjustments to the Company's delivery rates as a result of the reconciliation between allowed and actual billed revenues. Any difference is recorded as a regulatory asset or regulatory liability.

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 DPU. Carrying charges are not recorded on items for which expenditures have not yet been made.

6. RATE MATTERS

General Rate Case

Effective October 1, 2018, the DPU approved a combined rate increase for the Company and its affiliate, Colonial Gas. The DPU authorized an allowed return on equity of 9.5% and an equity ratio of 53%. In addition, the DPU approved funding the Gas Business Enablement program. The Gas Business Enablement program is being developed to consolidate and modernize the Company's systems and operating platforms to facilitate internal efficiencies and improve customers' experience. The DPU denied the Company's request to increase rates for certain post-test year capital investments, instead requiring the Company to include those investments in a subsequent base rate case. The Company filed a motion for reconsideration of certain aspects of the DPU decision. The motion for reconsideration is still pending. The Company cannot predict the outcome of this motion.

Carrying Charge Adjustment

In August 2017, the DPU ordered the Company to provide, through the Company's pension and PBOP reconciling mechanism, compound interest on its PBOP carrying charges related to calendar years 2003 through 2006. The Company calculated the compound interest to be approximately $1.2 million and was ordered to revise its pending 2017 Pension Adjustment Factor ("PAF") petition and include this amount in the revised filing. The Order was in conjunction with the DPU's annual investigation of the Company's pension and PBOP reconciliation mechanism and the Massachusetts Attorney General's ("AG") contention that the Company is obligated to provide compound interest on its PBOP carrying charges, which the Company disputes. The Company complied with the DPU's order when it included the interest in its revised PAF filing submitted on October 24, 2017. The new PAF factor went into effect on November 1, 2017. The Company has also filed a motion for reconsideration of this matter to the DPU. The Company cannot predict the outcome of this matter at this time.

Tax Cuts and Jobs Act ("Tax Act")

In February 2018, the DPU opened an investigation to examine the effect of the Tax Act on the rates of the investor-owned utilities in Massachusetts as of January 1, 2018, and directed the utilities to account for any revenues associated with the difference between the previous and current corporate income tax rates, and establish a regulatory liability for excess recovery in rates of accumulated deferred income taxes ("ADIT"). The Company's filing was submitted to the DPU on May 1, 2018. In its June 29, 2018 order, the DPU allowed the Company to defer the effect of the tax reduction until new rates resulting from the then-pending rate case became effective on October 1, 2018, at which time the Company was directed to refund the three-month tax savings deferral to customers over one year, and the Company included this amount in its rate case compliance filing. On December 21, 2018, the DPU issued an order requiring all utilities to begin crediting in rates the amortization of excess deferred federal income taxes, to the extent such amortization was not already included in base distribution rates, through the combination of factors associated with certain reconciling mechanisms and a separate factor for the amortization of the remaining amounts. The Company included an estimate of amortization of excess deferred federal income taxes in its 2017 rate case, and the DPU required a filing by May 1, 2019 to update the balance of excess deferred federal income taxes and associated amortization. By Order dated September 24, 2018 in D.P.U. 18-15-D ("Order 18-15-D"), the DPU approved the Company and Colonial Gas' methodology for calculating the amount of excess ADIT and proposed amortization periods for protected and unprotected amounts. On May 1, 2019, consistent with the DPU's directives in Order 18-15-D, the Company and Colonial Gas provided a final calculation of protected and unprotected excess ADIT amounts, and a final calculation of the amortization periods applicable to protected excess ADIT.

In February 2019, the DPU issued an order finding that the Massachusetts utilities were not required to refund tax savings previously accrued from January 1, 2018 through June 30, 2018 as a result of the federal income tax rate reduction. On March 7, 2019, the AG's office filed a motion for clarification and reconsideration requesting that the DPU provide additional clarity regarding its February 2019 ruling, and to reconsider its determination to allow utilities to keep the federal tax savings accrued from January 1, 2018 through June 30, 2018. The Company has recorded a $5.7 million regulatory liability pending the outcome of the AG's motion.

Update of Rates and Statement of Operating Conditions for Interstate Transportation Services

The Company is a so-called "Hinshaw Pipeline" in that it uses its distribution system to provide limited interstate transportation services. Federal Energy Regulatory Commission ("FERC") rules and regulations require Hinshaw Pipelines to obtain a blanket certificate to sell or transport gas in interstate commerce at specific rates and to subsequently make new rate election filings in certain circumstances. The FERC regulations require the Company to make a new rate election if the state-approved rate used for the Company's current rate election is changed to reflect the reduced income tax rates adopted in the Tax Act. The DPU put in place rate adjustments resulting from reduced tax costs because of the Tax Act. Accordingly, the Company was required to make a new rate election at the FERC. On November 30, 2018, and as corrected on March 12, 2019, the Company filed with the FERC tariff records to reflect revised rates in compliance with the above-referenced rules and regulations. On April 25, 2019, the FERC approved the tariff filing made by the Company to update its rates and Statement of Operating conditions for the use of its distribution system to provide interstate transportation services.

Independent Statewide Pipeline Safety Audit

On November 30, 2018, the DPU initiated an independent statewide pipeline safety audit of the natural gas distribution systems in Massachusetts. The DPU hired an independent auditor, and, as part of Phase I of the audit, the Company submitted responses to Information Requests from the auditor and made a presentation to the auditor in January 2019. An oral report from the independent auditor with recommendations for Phase II of the audit was expected by the end of March 2019, but the Company has not yet received any information on Phase II of the audit. The auditor is assessing the safety of the gas system in the entire state and will be making recommendations for improvements that may impact the Company's operations and pipeline safety compliance requirements in the future. The Company doesn't anticipate that it will receive any penalties as a direct result of the audit, but the Company cannot predict the outcome of the audit at this time.

7. PROPERTY, PLANT, AND EQUIPMENT

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

	March 31,	
	2019	2018
	(in thousands of dollars)	
Plant and machinery	**$ 4,286,015**	$ 4,049,123
Land and buildings	**165,409**	78,203
Assets in construction	**233,635**	294,292
Software and other intangibles	**72,417**	72,417
Total property, plant, and equipment	**4,757,476**	4,494,035
Accumulated depreciation and amortization	**(1,072,930)**	(1,000,719)
Property, plant, and equipment, net	**$ 3,684,546**	$ 3,493,316

8. 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 operations. Any differences between actual pension 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 (deductions) income, net in the accompanying statements of operations. 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 Plan is a defined benefit plan which provides 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, 2019, 2018, and 2017, the Company made contributions of approximately $14.4 million, $15.3 million, and $13.8 million, respectively, to the Qualified Pension Plans. The Company expects to contribute approximately $22.4 million to the Qualified Pension Plans during the year ending March 31, 2020.

Benefit payments to Pension Plan participants for the years ended March 31, 2019, 2018, and 2017 were approximately $15.7 million, $18.5 million, and $11.3 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. During the years ended March 31, 2019, 2018, and 2017, the Company made contributions of approximately zero, $2.7 million, and $4.2 million respectively, to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2020.

Benefit payments to PBOP Plan participants for the years ended March 31, 2019, 2018, and 2017 were $7.4 million, $2.8 million, and $3.5 million, respectively.

Defined Contribution Plan

NGUSA has a defined contribution pension plan that covers substantially all employees. For the years ended March 31, 2019, 2018, and 2017, the Company recognized an expense in the accompanying statements of operations of $1.2 million, $1.8 million, and $1.5 million, respectively, for matching contributions.

Net Periodic Benefit Costs

The Company’s net periodic benefit pension costs for the years ended March 31, 2019, 2018, and 2017 were $11.5 million, $15.0 million, and $15.9 million, respectively.

The Company’s net periodic benefit PBOP costs for the years ended March 31, 2019, 2018, and 2017 were $2.6 million, $2.3 million, and $4.7 million, respectively.

Amounts Recognized in Regulatory Assets/Liabilities

The following tables summarize the Company’s changes in actuarial gains/losses and prior service costs recognized in regulatory assets/liabilities for the years ended March 31, 2019, 2018, and 2017:

	Pension Plans		
	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial loss (gain)	**$ 16,105**	$ 198	$ (4,842)
Amortization of net actuarial loss	**(8,294)**	(10,680)	(11,359)
Amortization of prior service cost, net	**(1,719)**	(1,732)	(1,618)
Total	**$ 6,092**	$ (12,214)	$ (17,819)
Recognized in regulatory assets (liabilities)	**$ 6,092**	$ (12,214)	$ (17,819)
Total	**$ 6,092**	$ (12,214)	$ (17,819)

	PBOP Plans		
	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial loss (gain)	**$ 8,266**	$ 2,218	$ (16,343)
Amortization of net actuarial gain	**40**	60	58
Amortization of prior service cost, net	**(44)**	(54)	(76)
Total	**$ 8,262**	$ 2,224	$ (16,361)
Recognized in regulatory assets (liabilities)	**$ 8,262**	$ 2,224	$ (16,361)
Total	**$ 8,262**	$ 2,224	$ (16,361)

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

The following tables summarize the Company’s amounts recognized in regulatory assets/liabilities on the balance sheet that have not yet been recognized as components of net actuarial loss at March 31, 2019, 2018, and 2017:

	Pension Plans		
	At March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial loss	**$ 40,516**	$ 32,705	$ 43,187
Prior service cost	**7,776**	9,495	11,227
Total	**$ 48,292**	$ 42,200	$ 54,414
Recognized in regulatory assets	**$ 48,292**	$ 42,200	$ 54,414
Total	**$ 48,292**	$ 42,200	$ 54,414

	PBOP Plans		
	At March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial loss (gain)	**$ 9,449**	$ 1,143	$ (4,807)
Prior service cost	**(8)**	36	126
Total	**$ 9,441**	$ 1,179	$ (4,681)
Recognized in regulatory assets (liabilities)	**$ 9,441**	$ 1,179	$ (4,681)
Total	**$ 9,441**	$ 1,179	$ (4,681)

The amount of net actuarial loss and prior service cost to be amortized from regulatory assets during the year ending March 31, 2020 for the Pension Plans is $5.8 million and $2.9 million, respectively, and net actuarial loss to be amortized from regulatory assets during the year ending March 31, 2020 for the PBOP Plans is $0.1 million.

Amounts Recognized on the Balance Sheet

The following table summarizes the portion of the funded status that is recognized on the Company's balance sheet at March 31, 2019 and 2018:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2019	2018	**2019**	2018
	(in thousands of dollars)			
Projected benefit obligation	**$ (386,256)**	$ (370,763)	**$ (118,698)**	$ (110,681)
Fair value of plan assets	**419,540**	405,899	**40,766**	41,065
Total	**$ 33,284**	$ 35,136	**$ (77,932)**	$ (69,616)
Other non-current assets	**$ 33,284**	$ 35,136	**$ -**	$ -
Other non-current liabilities	**-**	-	**(77,932)**	(69,616)
Total	**$ 33,284**	$ 35,136	**$ (77,932)**	$ (69,616)

Expected Benefit Payments

Based on current assumptions, the following benefit payments are expected subsequent to March 31, 2019 in respect of the Company:

(in thousands of dollars)

Years Ended March 31,	Pension Plans	PBOP Plans
2020	$ 16,677	$ 6,954
2021	17,229	7,314
2022	17,872	7,653
2023	18,384	8,031
2024	18,924	8,351
2025-2029	100,463	44,857
Total	$ 189,549	$ 83,160

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	Years Ended March 31,		
	2019	2018	2017
Benefit Obligations:			
Discount rate	**4.10%**	4.10%	4.30%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.50%**	6.25%	6.50%
Net Periodic Benefit Costs:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.25%**	6.50%	6.50%

	PBOP Plans		
	Years Ended March 31,		
	2019	2018	2017
Benefit Obligations:			
Discount rate	**4.10%**	4.10%	4.30%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.50%-7.25%**	6.25%-6.75%	6.50%-6.75%
Net Periodic Benefit Costs:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.25%-6.75%**	6.50%-6.75%	6.50%-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 Hewitt AA Above Median 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,	
	2019	2018
Health care cost trend rate assumed for next year		
Pre-65	**7.25%**	7.50%
Post-65	**5.75%**	5.75%
Prescription	**9.75%**	10.25%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre-65	**2028**	2028
Post-65	**2026**	2026
Prescription	**2027**	2027

Plan Assets

NGUSA, as the Plans' sponsor, manages the benefit plan investments to minimize the long-term cost of operating the Plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic study, which analyzes the Plans' liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income securities. 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. Small investments are also approved for private equity, real estate, and infrastructure, with the objective of 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 study. Investment risk and return are reviewed by NGUSA's Investment Committee on a quarterly basis.

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

The target asset allocations for the benefit plans as of March 31, 2019 and 2018 are as follows:

	Pension Plans		PBOP Union		PBOP Non-Union	
	March 31,		March 31,		March 31,	
	2019	2018	**2019**	2018	**2019**	2018
U.S. equities	**20%**	20%	**34%**	34%	**45%**	45%
Global equities (including U.S.)	**7%**	7%	**12%**	12%	**0%**	0%
Global tactical asset allocation	**10%**	10%	**17%**	17%	**0%**	0%
Non-U.S. equities	**10%**	10%	**17%**	17%	**25%**	25%
Fixed income	**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%
Total	**100%**	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

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

	March 31, 2019				
	Level 1	**Level 2**	**Level 3**	**Not Categorized**	**Total**
			(in thousands of dollars)		
Pension Assets					
Cash and cash equivalents	$ -	$ 4,505	$ -	$ 71,620	$ 76,125
Accounts receivable	142,262	-	-	-	142,262
Accounts payable	(251,231)	-	-	-	(251,231)
Equity	376,893	-	-	1,298,495	1,675,388
Fixed income securities	-	1,230,062	-	671,615	1,901,677
Preferred securities	-	11,302	-	-	11,302
Private equity	-	-	-	299,528	299,528
Real estate	-	-	-	219,668	219,668
Other	124,129	367	-	324,661	449,157
Total	**$ 392,053**	**$ 1,246,236**	**$ -**	**$ 2,885,587**	**$ 4,523,876**
PBOP Assets					
Cash and cash equivalents	$ 18,938	$ -	$ -	$ -	$ 18,938
Accounts receivable	3,922	-	-	-	3,922
Accounts payable	(1)	-	-	-	(1)
Equity	170,220	-	-	532,528	702,748
Fixed income securities	3,246	227,196	-	-	230,442
Private equity	-	-	-	700	700
Other	89,751	-	-	236,443	326,194
Total	**$ 286,076**	**$ 227,196**	**$ -**	**$ 769,671**	**$ 1,282,943**

	March 31, 2018				
	Level 1	Level 2	Level 3	Not Categorized	Total
	(in thousands of dollars)				
Pension Assets					
Cash and cash equivalents	$ 1,331	$ 20,844	$ -	$ 72,420	$ 94,595
Accounts receivable	196,817	-	-	-	196,817
Accounts payable	(298,572)	-	-	-	(298,572)
Equity	582,386	-	-	1,238,311	1,820,697
Fixed income securities	149	1,093,506	-	637,665	1,731,320
Preferred securities	-	11,725	-	-	11,725
Private equity	-	-	-	260,209	260,209
Real estate	-	-	-	208,488	208,488
Other	2,370	-	-	303,504	305,874
Total	**$ 484,481**	**$ 1,126,075**	**$ -**	**$ 2,720,597**	**$ 4,331,153**
PBOP Assets					
Cash and cash equivalents	$ 15,390	$ 6	$ -	$ 22	$ 15,418
Accounts receivable	1,733	-	-	-	1,733
Accounts payable	(136)	-	-	-	(136)
Equity	241,131	-	-	536,938	778,069
Fixed income securities	6,428	236,732	-	192	243,352
Preferred securities	-	4	-	-	4
Private equity	-	-	-	4,310	4,310
Real estate	-	-	-	63	63
Other	35,738	-	-	229,677	265,415
Total	**$ 300,284**	**$ 236,742**	**$ -**	**$ 771,202**	**$ 1,308,228**

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

Cash and cash equivalents: Cash and cash equivalents that can be priced daily are classified as Level 1. Active reserve funds, reserve deposits, commercial paper, repurchase agreements, and commingled cash equivalents are classified as Level 2. Cash and cash equivalents invested in commingled money market investment funds which have NAV used as a practical expedient pricing per fund share are excluded from the fair value hierarchy.

Accounts receivable and accounts payable: Accounts receivable and accounts payable are classified as Level 1. Such amounts are short-term and settle within a few days of the measurement date.

Equity and preferred securities: Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded. Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. If the Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, the securities are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV used as a practical expedient per fund share, derived from the underlying securities' quoted prices in active markets. These investments are excluded from the fair value hierarchy.

Fixed income securities: Fixed income securities (which include corporate debt securities, municipal fixed income securities, U.S. Government and Government agency securities including government mortgage-backed securities, index-linked government bonds, and state and local bonds), convertible securities, and investments in securities lending collateral (which include repurchase agreements, asset-backed securities, floating rate notes, and time deposits) are valued with an institutional bid valuation. A bid valuation is an estimated price a dealer would pay for a security (typically in an institutional round lot). Oftentimes, these evaluations are based on proprietary models, which pricing vendors establish for these purposes. In some cases, there may be manual sources when primary vendors do not supply prices. Fixed income investments are primarily comprised of fixed income securities and fixed income commingled funds. The prices for direct investments in fixed income securities are generated on a daily basis. Prices generated from less active trading with wider bid ask prices are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV used as a practical expedient per fund share. These investments are excluded from the fair value hierarchy.

Private equity and real estate: Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital, and other investments are valued using evaluations (NAV used as a practical expedient per fund share) based on proprietary models or based on the NAV used as a practical expedient. Investments in private equity and real estate funds are primarily invested in privately held real estate investment properties, trusts, and partnerships as well as equity and debt issued by public or private companies. The Company's interest in a fund or partnership is estimated based on the NAV used as a practical expedient. The Company's interest in these funds cannot be readily redeemed due to the inherent lack of liquidity and the primarily long-term nature of the underlying assets. Distribution is made through the liquidation of the underlying assets. The Company views these investments as part of a long-term investment strategy. These investments are valued by each investment manager based on the underlying assets. The funds utilize valuation techniques consistent with the market, income, and cost approaches to measure the fair value of certain real estate investments. The majority of the underlying assets are valued using significant unobservable inputs and often require significant management judgment or estimation based on the best available information. Market data includes observations of the trading multiples of public companies considered comparable to the private companies being valued. Investments in limited partnerships with redemption restrictions and that use NAV as a practical expedient are excluded from the fair value hierarchy.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the NAV used as a practical expedient could result in a different fair value measurement at the reporting date.

9. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2019 are as follows:

(in thousands of dollars) Fiscal Years Ending March 31,		
2020	$	7,000
2021		5,000
2022		15,000
2023		10,000
2024		16,000
Thereafter		1,030,000
Total	$	1,083,000

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. During the years ended March 31, 2019 and 2018, the Company was in compliance with all such covenants.

10. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Current tax (benefit) expense:			
Federal	**$ (38,287)**	$ (5,935)	$ 4,781
State	**(16,313)**	395	2,402
Total current tax (benefit) expense	**(54,600)**	(5,540)	7,183
Deferred tax expense:			
Federal	**1,521**	39,694	30,478
State	**5,865**	8,742	6,337
Total deferred tax expense	**7,386**	48,436	36,815
Total income tax (benefit) expense	**$ (47,214)**	$ 42,896	$ 43,998

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2019, 2018, and 2017 were 27.1%, 36.7%, and 40.5%, respectively. The following table presents a reconciliation of income tax (benefit) expense at the federal statutory tax rate of 21.0%, 31.55%, and 35.0%, respectively, to the actual tax expense:

	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Computed tax	**$ (36,585)**	$ 36,860	$ 38,010
Change in computed taxes resulting from:			
State income tax, net of federal benefit	**(8,254)**	6,196	5,681
Amortization of excess deferred federal income taxes	**(2,502)**	-	-
Other items, net	**127**	(160)	307
Total changes	**(10,629)**	6,036	5,988
Total income tax (benefit) expense	**$ (47,214)**	$ 42,896	$ 43,998

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

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law. The Tax Act includes significant changes to various federal tax provisions applicable to the Company, including provisions specific to regulated public utilities. The most significant changes include the reduction in the corporate federal income tax rate from 35.0% to 21.0% effective January 1, 2018, the elimination of bonus depreciation for certain property acquired or placed in service after September 27, 2017, and the extension of the normalization requirements for ratemaking treatment of excess deferred taxes.

On August 3, 2018, the Internal Revenue Service (“IRS”) and the U.S. Department of Treasury released proposed regulations associated with the bonus depreciation rules enacted as part of the Tax Act. The proposed regulations would enable utilities to claim additional bonus depreciation on property acquired and placed in service between September 28, 2017 and March 31, 2018. The Company adopted the guidance in the proposed regulations and claimed the additional six months of bonus depreciation on its fiscal year 2018 federal income tax return.

In accordance with ASC 740, "Income Taxes," the effects of changes in tax law are required to be recognized in the period of enactment, which for the Company was the period ended March 31, 2018. Since the Company's fiscal year end is March 31, the statutory rate applicable for the Company's fiscal year ended March 31, 2018 was a blended tax rate of 31.55%. For the fiscal year ended March 31, 2019 and future periods, the federal income tax rate is 21.0%. In addition, ASC 740, "Income Taxes," requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. As a result, the Company remeasured its federal deferred income tax assets and liabilities using the newly enacted tax rate of 21.0%.

On December 22, 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118, which provides guidance on accounting for the effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740, "Income Taxes". To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements. As of March 31, 2019, any and all provisional amounts previously recorded in accordance with SAB 118 have been adjusted to reflect their final amounts.

As of March 31, 2018, the remeasurement amounted to a decrease in the net deferred income tax liability of $197.5 million, of which $0.3 million was recorded to deferred income tax expense and $197.8 million was recorded as a regulatory liability for the refund of excess accumulated deferred income taxes to the ratepayers ("excess ADIT"). During the current period, the Company adjusted the remeasurement of the net deferred income tax liability by $2.9 million, which was recorded as an increase to the regulatory liability for excess ADIT. As of March 31, 2019, the regulatory liability for excess ADIT on a pre-tax basis prior to amortization amounted to $276.1 million ($200.7 million post-tax).

Deferred Tax Components

	March 31,	
	2019	2018
	(in thousands of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	**$ 16,415**	$ 13,676
Environmental remediation costs	**11,776**	12,052
Future federal benefit on state taxes	**17,414**	14,930
Postretirement benefits and other employee benefits	**16,194**	13,166
Regulatory liabilities - other	**28,963**	13,850
Regulatory liabilities - taxes	**74,072**	74,196
Net operating losses	**41,492**	25,840
Other items	**7,809**	20,610
Total deferred tax assets	**$ 214,135**	$ 188,320
Deferred tax liabilities:		
Property-related differences	**$ 456,424**	$ 428,196
Regulatory assets - deferred gas costs	**29,891**	23,477
Other items	**43,598**	44,613
Total deferred tax liabilities	**$ 529,913**	$ 496,286
Deferred income tax liabilities, net	**$ 315,778**	$ 307,966

Net Operating Losses

The amounts and expiration dates of the Company's net operating loss carryforwards as of March 31, 2019 are as follows:

	Carryforward Amount		Expiration Period
	(in thousands of dollars)		
Federal	$	277,723	2033-2038
State		35,673	2036-2037

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.

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other (deductions) income, net, in the accompanying statements of operations. As of March 31, 2019 and 2018, the Company has accrued for interest related to unrecognized tax benefits of $7.3 million and $4.3 million, respectively. During the years ended March 31, 2019, 2018, and 2017, the Company recorded interest expense related to unrecognized tax benefits of $3.0 million, $1.6 million, and $0.6 million, respectively. No tax penalties were recognized during the years ended March 31, 2019, 2018, or 2017.

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.

During the year ended March 31, 2019, the Company reached a settlement with the IRS for the tax years ended August 24, 2007, March 31, 2008, and March 31, 2009. The outcome of the settlement did not have a material impact on the Company's results of operations, financial position, or cash flows. The IRS continues its examination of the next audit cycle, which includes the income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is expected to conclude in the next fiscal year and result in a settlement agreement with the IRS. The Company does not anticipate the settlement will have a material impact on the Company's financial position. As a result of both settlements with the IRS, a refund of $30.1 million is expected to be received within the next 12 months. The income tax returns for the years ended March 31, 2013 through March 31, 2019 remain subject to examination by the IRS.

The state of Massachusetts is in the process of examining the Company's income tax returns for the years ended March 31, 2010 through March 31, 2012. The income tax returns for the years ended March 31, 2013 through March 31, 2019 remain subject to examination by the state of Massachusetts.

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

Jurisdiction	Tax Year
Federal	March 31, 2010
Massachusetts	March 31, 2010

11. 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.

Within the Commonwealth of Massachusetts, the Company is aware of numerous former MGP sites and related facilities within the existing or former service territories of the Company. Investigation and remediation expenditures incurred for the years ended March 31, 2019, 2018, and 2017 were $0.7 million, $1.7 million, and $6.3 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $40.6 million and $41.6 million at March 31, 2019 and 2018, respectively. These costs are expected to be incurred over approximately 50 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.

By rate orders, the DPU has provided for the recovery of site investigation and remediation costs. Accordingly, as of March 31, 2019 and 2018, the Company has recorded environmental regulatory assets of $55.5 million (including $1.1 million related to LDAC) and $58.8 million, respectively.

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

12. COMMITMENTS AND CONTINGENCIES

Operating Lease Commitments

The Company has various operating leases relating to office space. Total rental expense for operating leases included in operations and maintenance expense in the accompanying statements of operations was $4.4 million, $2.5 million, and $1.8 million for the years ended March 31, 2019, 2018, and 2017, respectively.

The future minimum lease payments for the years subsequent to March 31, 2019 are as follows:

(in thousands of dollars) Years Ending March 31,	
2020	$ 3,969
2021	4,013
2022	3,993
2023	4,001
2024	3,863
Thereafter	28,269
Total	$ 48,108

Purchase Commitments

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, 2019 are summarized in the table below:

(in thousands of dollars) Years Ending March 31,	Gas Purchases
2020	$ 222,549
2021	200,642
2022	160,580
2023	155,644
2024	152,432
Thereafter	826,674
Total	$ 1,718,521

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.

Reconnection Fees Settlement

In fiscal year 2017, the Company reported to the DPU and the AG's office that it erroneously charged reconnection fees to certain customers. These amounts have been refunded or are in the process of being refunded to customers. Additionally, the AG's office imposed a $2.7 million penalty related to this matter, which was settled in fiscal year 2018. As of March 31, 2018, the Company recorded a $1.9 million liability for the balance of fees to be refunded to customers.

On March 6, 2018, the Company and its affiliate, Colonial Gas, signed a Settlement Agreement with the AG on the gas reconnection issue. In addition to the $1.6 million that the Company and Colonial Gas previously credited to affected customers, the companies established a Restitution Fund in the amount of $2.3 million (of which $1.9 million related to the Company) for those customers that had previously not been located. This amount included interest for each reconnection fee. Under the Settlement Agreement, the Company had one year to refund the remaining balance to customers, and, after one year, any remaining balance shall be refunded to all customers through the Residential Assistance Adjustment Factor ("RAAF"). As of March 31, 2019, the Restitution Fund was closed, and the remaining balance will be refunded to all customers via the RAAF.

Colonial Gas Consent Solicitation

On March 13, 2019, Colonial Gas commenced a consent solicitation, proposing certain amendments and modifications to its Second Amended and Restated First Mortgage Indenture dated as of June 15, 1992 as amended (the "Indenture"), relating to its issued and outstanding first mortgage bonds under the Indenture (the "Bonds"). Colonial Gas has received consent from the holders of the Bonds with respect to certain amendments to the Indenture ("Consent Solicitation"). The purposes of the amendments are to, among other things, (i) limit the assets covered by the lien of the Indenture to the legacy assets of the Company prior to the intended legal merger of Colonial Gas and the Company (the "Merger"), and any repairs, renewals, or replacements to such assets, (ii) limit certain other covenants in the Indenture to this same scope of assets, (iii) revise certain financial covenants therein, and (iv) add a governing law provision to the Indenture.

The Company has requested authorization from the DPU to complete the Merger. If the proposed Merger is approved by the DPU, it is expected that Colonial Gas will merge with and into the Company, and the Company will be the surviving entity in accordance with Massachusetts law. As a result of the Merger, and by operation of the law, the facilities, properties and other rights, assets, franchises, and liabilities of both companies will vest in the Company as the successor by merger to Colonial Gas. Colonial Gas will cease to exist, and the Company will be the sole surviving corporate entity. Provided the DPU approves the proposed Merger, no additional consents from the holders of the Bonds will be required to progress the Merger.

Other Contingencies

At March 31, 2019 and 2018, the Company had accrued workers' compensation, auto, and general insurance claims which have been incurred but not yet reported ("IBNR") of $12.8 million and $11.2 million, respectively. IBNR reserves have been established for claims and/or events that have transpired but have not yet been reported to the Company for payment.

13. 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,	
	2019	2018	**2019**	2018
	(in thousands of dollars)			
Colonial Gas Company	**$ 881**	$ 1,059	**$ 4,772**	$ 5,033
KeySpan Corporation	**-**	658	**-**	-
National Grid Engineering Services, LLC	**20**	1,966	**115**	113
NGUSA	**159**	818	**60,956**	1,473
NGUSA Service Company	**7,819**	4,268	**19,526**	21,621
Other Affiliates	**843**	159	**1,583**	649
Total	**$ 9,722**	$ 8,928	**$ 86,952**	$ 28,889

Intercompany Money Pool

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

The Regulated Money Pool is funded by operating funds from participants. NGUSA has the ability to borrow up to $3.0 billion from National Grid plc for working capital needs, including funding of the Regulated Money Pool, if necessary. The Company had short-term intercompany money pool borrowings of $371.2 million and $167.5 million at March 31, 2019 and 2018, respectively. The average interest rates for the intercompany money pool were 2.4%, 1.6%, and 1.1% for the years ended March 31, 2019, 2018, and 2017, respectively

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. 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, which for the years ended March 31, 2019, 2018, and 2017 were $285.0 million (inclusive of work continuation), $194.0 million, and $219.4 million, respectively.