Central Maine Power Company and Subsidiaries

Consolidated Financial Statements

As of and for the Years Ended December 31, 2021 and 2020

Central Maine Power Company
and Subsidiaries

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Shareholder and Board of Directors
Central Maine Power Company:

Opinion

We have audited the consolidated financial statements of Central Maine Power Company and its subsidiaries (the Company), which comprise the consolidated balance sheets as of December 31, 2021 and 2020, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

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

Responsibilities of Management for the Consolidated Financial Statements

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

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

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

KPMG LLP

New York, New York
March 24, 2022

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,		2021		2020
(Thousands)				
Operating Revenues	$	**978,399**	$	**888,225**
Operating Expenses				
Electricity purchased		29,518		19,497
Operations and maintenance		486,685		443,678
Depreciation and amortization		127,761		123,156
Taxes other than income taxes, net		76,252		73,895
Total Operating Expenses		**720,216**		**660,226**
Operating Income		**258,183**		**227,999**
Other income		19,197		16,369
Other deductions		(17,355)		(15,899)
Interest expense, net of capitalization		(46,347)		(46,148)
Income Before Income Tax		**213,678**		**182,321**
Income tax expense		30,790		41,681
Net Income		**182,888**		**140,640**
Less: net income attributable to noncontrolling interest		3,055		2,430
Net Income Attributable to CMP	$	**179,833**	$	**138,210**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31,		2021		2020
(Thousands)				
Net Income	$	**182,888**	$	**140,640**
Other Comprehensive Income (Loss), Net of Tax				
Amortization of pension cost for nonqualified plans, net of income tax		83		(188)
Unrealized gain (loss) during period on derivatives qualifying as cash flow hedges, net of income tax		203		(257)
Reclassification to net income of (gain) loss on cash flow hedges, net of income tax		(121)		245
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax		85		130
Other Comprehensive Income (Loss), Net of Tax		**250**		**(70)**
Comprehensive Income		**183,138**		**140,570**
Less:				
Comprehensive income attributable to noncontrolling interest		3,055		2,430
Comprehensive Income Attributable to CMP	$	**180,083**	$	**138,140**

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 24,407	$ 23,855
Accounts receivable and unbilled revenues, net	246,793	241,407
Accounts receivable from affiliates	63,855	1,408
Materials and supplies	35,726	24,674
Prepayments and other current assets	17,896	20,162
Income tax receivable	—	32,727
Regulatory assets	49,860	49,248
Total Current Assets	**438,537**	**393,481**
Utility plant, at original cost	4,949,841	4,699,672
Less accumulated depreciation	(1,368,654)	(1,261,090)
Net Utility Plant in Service	**3,581,187**	**3,438,582**
Construction work in progress	243,817	358,843
Total Utility Plant	**3,825,004**	**3,797,425**
Operating lease right-of-use assets	14,774	15,549
Other property and investments	901	846
Regulatory and Other Assets		
Regulatory assets	396,121	475,985
Goodwill	324,938	324,938
Other	158,230	28,149
Total Regulatory and Other Assets	**879,289**	**829,072**
Total Assets	**$ 5,158,505**	**$ 5,036,373**

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 124,578	$ 149,549
Notes payable to affiliates	1,146	72,974
Accounts payable and accrued liabilities	192,853	229,153
Accounts payable to affiliates	38,263	8,124
Interest accrued	19,948	22,693
Taxes accrued	15,349	9,490
Operating lease liabilities	1,161	1,146
Other current liabilities	85,151	66,487
Regulatory liabilities	37,912	24,135
Total Current Liabilities	**516,361**	**583,751**
Regulatory and Other Liabilities		
Regulatory liabilities	356,608	403,228
Other Non-current liabilities		
Deferred income taxes	646,330	595,593
Pension and other postretirement	110,920	181,503
Operating lease liabilities	14,791	15,204
Other	163,209	36,403
Total Regulatory and Other Liabilities	**1,291,858**	**1,231,931**
Non-current debt	1,161,019	1,085,966
Total Liabilities	**2,969,238**	**2,901,648**
Commitments and Contingencies		
Redeemable Preferred Stock	**571**	**571**
CMP Common Stock Equity		
Common stock ($5 par value, 80,000,000 shares authorized and 31,211,471 shares outstanding at December 31, 2021 and 2020)	156,057	156,057
Additional paid-in capital	950,478	824,039
Retained earnings	1,050,487	1,125,689
Accumulated other comprehensive loss	(3,543)	(3,793)
Total CMP Common Stock Equity	**2,153,479**	**2,101,992**
Noncontrolling interest	35,217	32,162
Total Equity	**2,188,696**	**2,134,154**
Total Liabilities and Equity	**$ 5,158,505**	**$ 5,036,373**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,	2021	2020
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 182,888**	**$ 140,640**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	127,761	123,156
Regulatory assets/liabilities amortization	16,052	(2,303)
Regulatory assets/liabilities carrying cost	(4,030)	(1,076)
Amortization of debt issuance costs	493	658
Deferred taxes	24,065	42,861
Pension cost	17,459	14,478
Stock-based compensation	572	256
Accretion expenses	52	49
Gain on disposal of assets	(29)	(432)
Other non-cash items	(8,231)	(4,493)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(67,833)	(34,870)
Inventories	(11,052)	(5,886)
Accounts payable, to affiliates, and accrued liabilities	24,580	46,129
Taxes accrued	10,964	24,534
Other assets/liabilities	59,994	(30,722)
Regulatory assets/liabilities	(42,840)	(97,291)
Net Cash Provided by Operating Activities	**330,865**	**215,688**
Cash Flow from Investing Activities:		
Utility plant additions	(236,790)	(347,858)
Contributions in aid of construction	57,060	15,196
Notes receivable from affiliates	—	23,020
Proceeds from sale of utility plant	814	2,412
Investments, net	—	63
Net Cash Used in Investing Activities	**(178,916)**	**(307,167)**
Cash Flow from Financing Activities:		
Non-current note issuance	199,644	49,696
Repayments of non-current debt	(150,000)	(993)
Repayments of finance leases	(254)	(925)
Notes payable to affiliates	(71,828)	72,269
Capital contribution	126,076	60,000
Dividends paid	(255,035)	(80,000)
Net Cash (Used in) Provided by Financing Activities	**(151,397)**	**100,047**
Net Increase in Cash and Cash Equivalents	**552**	**8,568**
Cash and Cash Equivalents, Beginning of Year	**23,855**	**15,287**
Cash and Cash Equivalents, End of Year	**$ 24,407**	**$ 23,855**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Changes in Equity

(Thousands, except per share amounts)	CMP Stockholder							
	Number of shares (*)	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total CMP Common Stock Equity	Non-controlling Interest	Total Common Stock Equity
Balances, December 31, 2019	**31,211,471**	**$ 156,057**	**$ 764,170**	**$1,067,514**	**$ (3,723)**	**$ 1,984,018**	**$ 29,732**	**$ 2,013,750**
Adoption of accounting standards	—	—	(275)	—	—	(275)	—	(275)
Net income	—	—	—	138,210	—	138,210	2,430	140,640
Other comprehensive loss, net of tax	—	—	—	—	(70)	(70)	—	(70)
Comprehensive income								140,570
Stock-based compensation	—	—	144	—	—	144	—	144
Capital contribution from parent	—	—	60,000	—	—	60,000	—	60,000
Preferred stock dividends	—	—	—	(35)	—	(35)	—	(35)
Common stock dividends	—	—	—	(80,000)	—	(80,000)	—	(80,000)
Balances, December 31, 2020	**31,211,471**	**156,057**	**824,039**	**1,125,689**	**(3,793)**	**2,101,992**	**32,162**	**2,134,154**
Net income	—	—	—	179,833	—	179,833	3,055	182,888
Other comprehensive income, net of tax	—	—	—	—	250	250	—	250
Comprehensive income								183,138
Stock-based compensation	—	—	363	—	—	363	—	363
Capital contribution from parent	—	—	126,076	—	—	126,076	—	126,076
Preferred stock dividends	—	—	—	(35)	—	(35)	—	(35)
Common stock dividends	—	—	—	(255,000)	—	(255,000)	—	(255,000)
Balances, December 31, 2021	**31,211,471**	**$ 156,057**	**$ 950,478**	**$1,050,487**	**$ (3,543)**	**$ 2,153,479**	**$ 35,217**	**$ 2,188,696**

(*) Par value of share amounts is $5

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

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

Background and nature of operations: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 653,170 customers as of December 31, 2021, in a service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas. We operate under the authority of the Maine Public Utilities Commission (MPUC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

CMP consists of the following subsidiaries: Maine Electric Power Company, Inc. (MEPCO) is a 78.3% owned subsidiary of CMP with the remaining 21.7% owned by Emera Maine (EM) which is wholly-owned by Emera, Inc. On March 24, 2020, Emera Maine was purchased by ENMAX Corp. As part of the sale, the company was required to change its name to Versant Power (Versant) and there was no impact to CMP's financial statements. Chester SVC Partnership (the Partnership or Chester) is a general partnership between NORVARCO, a wholly-owned subsidiary of CMP, which owns 50% interest in the Partnership and Bangor Var Co., Inc., a wholly-owned subsidiary of Versant, which owns the remaining 50% interest organized on October 9, 1990, under the Maine Uniform Partnership Act.

CMP is the principal operating utility of CMP Group, Inc. (CMP Group), a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, proposed in a joint bid by CMP and Hydro-Québec, was selected by the Massachusetts electric distribution utilities and the Massachusetts Department of Energy Resources in the Commonwealth of Massachusetts' 83D clean energy Request for Proposal. The NECEC transmission project includes a 145-mile transmission line linking the electrical grids in Québec, Canada and New England.

Basis of presentation: The accompanying consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and are presented on a consolidated basis, and therefore include the accounts of CMP and its consolidated subsidiaries, MEPCO and NORVARCO, and Chester. All intercompany transactions and accounts have been eliminated in consolidation in all periods presented.

Significant Accounting Policies: We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our consolidated financial statements:

***Principles of consolidation*:** We consolidate the entities in which we have a controlling financial interest, after the elimination of intercompany transactions. We account for investments in common stock where we have the ability to exercise significant influence, but not control, using the equity method of accounting.

***Revenue recognition*:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

Regulatory accounting: We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our consolidated statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

Noncontrolling interest: The noncontrolling interest represents the portion of our net income (loss), comprehensive income (loss) and net assets that is not allocable to us and is calculated based on our ownership percentage.

***Goodwill*:** Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred, the fair value of any noncontrolling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

Utility plant: We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.5% of average depreciable property for both 2021 and 2020. We amortize our capitalized software cost, which is included in other plant, using the straight line method, based on useful lives of 5 to 15 years. Capitalized software costs were approximately $171.3 million as of December 31, 2021, and $165.6 million as of December 31, 2020. Depreciation expense was $118.3 million in 2021 and $113.4 million in 2020. Amortization of capitalized software was $9.5 million in 2021 and $9.8 million in 2020.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	**Estimated useful life range (years)**	**2021**	**2020**
(Thousands)			
Electric			
Transmission	4-70	$ 2,719,219	$ 2,642,294
Distribution	15-82	1,695,279	1,551,773
Vehicles	4-20	64,730	60,729
Other	5-52	470,613	444,876
Total Utility Plant in Service		**4,949,841**	**4,699,672**
Total accumulated depreciation		(1,368,654)	(1,261,090)
Total Net Utility Plant in Service		**3,581,187**	**3,438,582**
Construction work in progress		243,817	358,843
Total Utility Plant		**$ 3,825,004**	**$ 3,797,425**

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our consolidated balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

Fair value measurement: 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Derivatives and hedge accounting: Derivatives are recognized on our consolidated balance sheets at their fair value. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs, which we present in the same income statement line item as the earnings effect of the hedged item. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings.

Cash and cash equivalents: Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in “Cash and cash equivalents.” We classify book overdrafts representing outstanding checks in excess of funds on deposit as “Accounts payable and accrued liabilities” on our consolidated balance sheets. We report changes in book overdrafts in the operating activities section of the consolidated statements of cash flows.

Consolidated statements of cash flows: Supplemental disclosure of cash flow information is as follows:

(Thousands)		2021		2020
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	48,146	$	42,705
Income taxes (refunded) paid, net	$	(10,222)	$	6,275

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $4.3 million in 2021 and $10.6 million in 2020. Accrued liabilities for utility plant additions were $3.6 million in 2021 and $32.0 million in 2020.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing trade receivables, determined based on experience. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $41.6 million for 2021 and $32.2 million for 2020, and are shown net of an allowance for credit losses at December 31 of $19.0 million for 2021 and $23.8 million for 2020. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $7.8 million in 2021 and $14.1 million in 2020.

Trade receivables include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the MPUC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $11.4 million for 2021 and $4.8 million for 2020. DPA receivable balances at December 31 were $32.1 million for 2021 and $18.9 million for 2020.

Debentures, bonds and bank borrowings: We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our consolidated balance sheets.

Inventory: Inventory comprises materials and supplies that we use for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the consolidated balance sheets within “Materials and supplies.”

***Government grants*:** We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the consolidated statements of income in the period in which we incur the expenses.

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos and polychlorinated biphenyl-contaminated equipment. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity’s legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2021 and 2020.

Years Ended December 31,		**2021**		**2020**
(Thousands)				
ARO, beginning of year	$	975	$	926
Accretion expenses		52		49
ARO, end of year	**$**	**1,027**	**$**	**975**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including the removal of property upon termination of an easement, right-of-way or franchise.

Accrued removal obligations: We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2056.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over the average remaining service period or 10 years. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes: AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, CMP settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax payable balance due to AGR at December 31, 2021 was $12.3 million. The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2020 was $32.8 million.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2021 and 2020.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current on our consolidated balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in "Taxes other than income taxes" and "Taxes accrued" in our consolidated financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other income” and “Other deductions” in our consolidated statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation; (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments; and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U.S. GAAP for: (1) franchise taxes that are partially based on income; (2) transactions with a government that result in a step up in the tax basis of goodwill; (3) separate financial statements of legal entities that are not subject to tax; and (4) enacted changes in tax laws in interim periods. We adopted the amendments effective January 1, 2021, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures. We are applying the amendments on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment requirement.

(b) Improvements to lessor accounting for certain leases with variable lease payments

In July 2021, the FASB issued amendments to make targeted improvements to ASC 842 for lessor's accounting for certain leases with variable lease payments, which affect lease classification. The amendments require a lessor to classify and account for a lease with variable lease payments as an operating lease if (a) the lease would have been classified as a sales-type lease or a direct financing lease and (b) the lessor would have otherwise recognized a day-one loss. The amendments are effective for fiscal years beginning after December 15, 2021, for all entities, and interim periods within those fiscal years for public business entities, with early application permitted. We have elected to early apply the amendments effective October 1, 2021, and apply the amendments prospectively to leases that commence or are modified on or after that date. Our adoption does not materially affect our consolidated results of operations, financial position and cash flows.

(c) Accounting for revenue contracts with customers acquired in a business combination

In October 2021, the FASB issued amendments related to the accounting for revenue contracts acquired in a business combination. The amendments require an entity (acquirer) to recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606, Revenue from Contracts with Customers. At the acquisition date, an acquirer should account for the related revenue contract in accordance with ASC 606 as if it had originated the contracts. Generally, this should result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree's financial statements. The amendments also provide certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. For public business entities, the amendments are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The amendments should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted. We have elected to early apply the amendments effective October 1, 2021. Our adoption did not materially affect our consolidated results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2021, that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(a) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments were effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Our prospective adoption of ASC 848 on January 1, 2022 will not materially affect our consolidated results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

In November 2021, the FASB issued amendments that apply to business entities (all entities except specified not-for-profit entities and employee benefit plans) that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance (such as a grant model within International Accounting Standards 20 Accounting for Government Grants and Disclosure of Government Assistance, or ASC Subtopic 958-605, Not-For-Profit Entities—Revenue Recognition). Government assistance can include tax credits (excluding transactions within the scope of Topic 740, Income Taxes), cash grants, grants of other assets, and project grants. Often, government assistance is provided to an entity for a particular purpose, and the entity promises to take specific actions. Transactions with a government, as used in ASC 832, Government Assistance, include assistance administered by domestic, foreign, local (city, town, county, municipal), regional (state, provincial, territorial), and national (federal) governments and entities related to those governments. The amendments require annual disclosures in notes to financial statements about transactions with a government as follows: (1) information about the nature of the transactions and the related accounting policy used to account for the transactions, (2) the line items on the balance sheet and income statement affected by the transactions, and the amounts applicable to each financial statement line item, and (3) significant terms and conditions of the transactions, including commitments and contingencies. For entities within scope the amendments are effective for annual periods beginning after December 15, 2021, with early application permitted. The amendments are to be applied either (1) prospectively to transactions within the scope of the amendments that are reflected in financial statements at the date of initial application and new transactions that are entered into after the date of initial application or (2) retrospectively to those transactions. Our adoption of the amendments on January 1, 2022 will not materially affect our disclosures.

***Use of estimates and assumptions*:** The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) environmental remediation liabilities; (10) AROs; (11) pension and other postretirement employee benefits (OPEB); and (12) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our consolidated financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 68% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. Distribution rates are established by the Maine Public Utilities Commission (MPUC) and transmission rates are established by the Federal Energy Regulatory Commission (FERC). The tariffs are applied based on the cost of providing service.

Electricity Distribution

The Maine distribution rate stipulation and the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case are some of the most important specific regulatory processes that currently affect CMP.

The revenues of CMP are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. The tariffs applied to regulated activities in the U.S. are approved by the regulatory commissions and are based on the cost of providing service. The revenues of each regulated utility are set to be sufficient to cover all its operating costs, including finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable ROE. Generally, tariff reviews cover various years and provide for a reasonable ROE, protection, and automatic adjustments for exceptional costs incurred.

Energy costs that are set on the New England wholesale markets are passed on to consumers by Competitive Energy Providers, licensed by the MPUC. Under Maine Law, transmission and distribution utilities are prohibited from providing retail energy supply. Default retail supply is provided by Standard Offer Providers periodically selected by the MPUC through a competitive procurement process.

Transmission - FERC ROE and Formula Rate Proceedings

CMP's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets.

On September 30, 2011, the Massachusetts Attorney General, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint with the FERC, pursuant to sections 206 and 306 of the Federal Power Act, against several New England Transmission Owners (NETOs) claiming that the approved base ROE of 11.14% used by NETOs in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).

On October 16, 2014, the FERC issued its final decision in the Complaint I setting the base ROE at 10.57%, and a maximum total ROE of 11.74% (base plus incentive ROE) for the October 2011 - December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the 15-month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the 15-month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP total reserve associated with Complaints II and III is $26.9 million as of December 31, 2021, which has not changed since December 31, 2020, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $17.1 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order).

Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. On November 19, 2020, FERC issued an order addressing arguments raised on the rehearing of its May 21, 2020 order, making minor adjustments to certain typographical errors with regard to some of the case inputs it included in its Risk Premium model analysis. However, those minor adjustments did not affect the outcome of the case, leaving the 10.02% ROE established by the May 21, 2020 order in place. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETOs submitted an amici curia brief in support of the MISO transmission owners on March 17, 2021. We cannot predict the outcome of these proceedings, including the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for our pending four Complaints.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after 3 years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately $1 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

CMP Distribution Rate Stipulation and New Renewable Source Generation

On May 1, 2013, CMP submitted its required distribution rate request with the Maine Public Utilities Commission (MPUC). On July 3, 2014, after a fourteen-month review process, CMP filed a rate stipulation agreement on the majority of the financial matters with the MPUC. The stipulation agreement was approved by the MPUC on August 25, 2014. The stipulation agreement also noted that certain rate design matters would be litigated, which the MPUC ruled on October 14, 2014.

The rate stipulation agreement provided for an annual CMP distribution tariff increase of 10.7% or $24.3 million. The rate increase was based on a 9.45% ROE and 50% equity capital. CMP was authorized to implement a Rate Decoupling Mechanism (RDM) which protects CMP from variations in sales due to energy efficiency and weather. CMP also adjusted its storm costs recovery mechanism whereby it is allowed to collect in rates a storm allowance and to defer actual storm costs when such storm event costs exceed $3.5 million. CMP and customers share Tier 2 (Large) storm costs that exceed a certain balance on a fifty-fifty basis, with CMP's exposure limited to $3.0 million annually. Tier 2 storms are defined as storms where the incremental restoration costs are between $3.5 million and $15.0 million.

CMP made a separate regulatory filing for a new customer billing system replacement. In accordance with the stipulation agreement, a new billing system is needed and CMP made its filing on February 27, 2015 to request a separate rate recovery mechanism. On October 20, 2015, the MPUC issued an order approving a stipulation agreement authorizing CMP to proceed with the customer billing system investment. The approved stipulation allows CMP to recover the system costs effective July 1, 2017.

The rate stipulation does not have a predetermined rate term. CMP has the option to file for new distribution rates at its own discretion. The rate stipulation does not contain service quality targets or penalties. The rate stipulation also does not contain any earning sharing requirements.

On July 24, 2018, the Maine Public Utilities Commission (MPUC), in response to a Ten Person Complaint, issued an order to initiate an investigation into the Company's rates and revenue requirements, and directed the Company to submit a rate case filing consistent with the requirements as specified in Chapter 120 of the Commission's rules no later than October 15, 2018. On October 15, 2018, CMP filed a general rate case as directed by the MPUC, requesting a ROE of 10% and an equity ratio of 55%. The company proposed to use savings arising out of changes in federal taxation pursuant to the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017 (the Tax Act) to keep its distribution prices stable while making its electric system more reliable. The MPUC established a ten-month process to review CMP's filing with a decision expected in August of 2019. Based on subsequent MPUC procedural orders, a decision was delayed until January 30, 2020.

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution service rates of $17.4 million or approximately 6.9%. The decision reflects an allowed base ROE of 9.25% and common equity ratio of 50%. However, the order implements a management efficiency adjustment, reducing this ROE by 100 basis points to address concerns with the Company's customer service performance during its implementation of a new customer billing system in 2017 and 2018. The management efficiency adjustment was to remain in effect until the Company demonstrated satisfactory customer service performance on four specified service quality measures for a period of 18 consecutive months, which commenced on March 1, 2020. In September 2021, the Company successfully met these metrics and filed a Petition with the MPUC to remove the adjustment. During deliberations held on February 17, 2022, the MPUC issued a verbal order approving the removal effective on the date of the order. The written order removing the management efficiency adjustment imposed upon CMP was issued on February 18, 2022.

The 2020 order also provided additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation. The MPUC order also retained the revenue decoupling mechanism implemented in 2014. The order denied the Company's request to increase rates for higher costs associated with services provided by its affiliates, Avangrid Service Company and Avangrid Management Company and instead initiated a management audit to assess the quality of these services as well as the impacts of the Avangrid management structure on the quality of CMP's customer service. The management audit commenced in August 2020 and the auditor's management audit report was issued for public comment on July 12, 2021. The

MPUC directed the Company to prepare and submit an implementation plan in December 2021 which the Company completed. On February 17, 2022, the MPUC deliberated and initiated an investigation into the impact the Avangrid Planning and Capital Budgeting process has on Maine ratepayers.

Pursuant to Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind farm under development near Monhegan Island, Maine. CMP's purchase obligations under the Maine Aqua Ventus contract will be approximately $12 million per year once the facility begins commercial operation. Pursuant to Maine law, the MPUC conducted two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 Million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%. Through contracts approved in December 2020 (Tranche 1), CMP was ordered to execute 13 contracts. In October 2021 CMP executed contracts with 6 additional facilities (Tranche 2). Each of the Tranche 1 and Tranche 2 are for 20-year terms. In accordance with MPUC orders, CMP either sells the purchased energy, or in one case the RECs, from these facilities in the ISO New England markets, through periodically auctioning the purchased output to wholesale buyers in the New England regional market, or through a sale to a third party for the RECs. Under Maine law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under Maine law, and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Summary Investigation into Security Limits Litigation

On December 13, 2021, the MPUC issued a Notice initiating a summary investigation of certain allegations with respect to the recovery of capital expenditure costs contained in the lawsuit filed by Security Limits, Inc. and Paul Silva against the Company, Networks and Iberdrola, S.A. and several other entities and individuals in the United States District Court Southern District of New York. CMP filed a report describing any costs described in the complaint that are currently being recovered or will be recovered in rates on January 18, 2022 as directed by the Notice of Summary Investigation. In the report, CMP noted that the plaintiffs' had not yet served the complaint upon Networks or the Company. The MPUC directed CMP to submit notification to the MPUC when the Complaint has been served or when the procedural deadline for serving the Complaint has passed. On February 9, 2022, Security Limits, Inc. and Paul Silva dismissed their complaint. On February 10, 2022, CMP notified the MPUC of the dismissal and requested that the proceeding be closed. Subsequently on March 8, 2022, the MPUC issued an Order closing the investigation.

Minimum Equity Requirements for Regulated Subsidiaries

CMP is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements CMP must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis CMP must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. CMP is prohibited by regulation from lending to unregulated affiliates. CMP has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements. We are in compliance with these requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $208.7 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and non-current regulatory assets at December 31, 2021 and 2020 consisted of:

As of December 31,	2021	2020
(Thousands)		
Current		
Transmission revenue reconciliation mechanism	$ 15,369	$ 31,276
Deferred meter replacement costs	1,981	2,004
Environmental remediation costs	380	126
Storm in rates	21,899	7,012
Stranded costs	4,421	2,117
Energy efficiency programs	4,732	6,116
Federal tax depreciation normalization adjustment	436	436
Other	642	161
Total current regulatory assets	**49,860**	**49,248**
Non-current		
Federal tax depreciation normalization adjustment	13,087	13,523
Storm costs	59,034	83,105
Unamortized losses on reacquired debt	165	258
Pension and other postretirement benefits costs	122,690	202,425
Unfunded future income taxes	173,834	150,687
Deferred meter replacement costs	20,925	22,930
Other	6,386	3,057
Total non-current regulatory assets	**$ 396,121**	**$ 475,985**

Deferred meter replacement costs represent the deferral of the net book value of retired meters which were replaced by advanced metering infrastructure meters. This amount is being amortized at the related existing depreciation amounts.

Energy efficiency programs represent the difference between revenue billed to customers through an energy efficiency charge and the costs of energy efficiency programs as approved by the state authorities.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Power Tax deferred income tax.

Pension and other postretirement represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. CMP is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. CMP's total deferral, including carrying costs, was $80.9 million at December 31, 2021 and $90.1 million at December 31, 2020.

Stranded cost represents costs that resulted from government-mandated long term Purchased Power Agreement (PPA) contracts between CMP and power producers (at prices above current market rates), which must be resold to the market at the current going rate. These costs and assets became "stranded" as CMP was prohibited from owning power and was therefore forced to sell the power back at the market rate, significantly lower than the PPA price. The monthly stranded cost over/under expense compared to revenue is recorded to be recovered in future years.

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. This mechanism contains the Annual Transmission True Up (ATU) which is recovered over the subsequent June to May period. When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve-month period as the related revenues are collected (refunded). Transmission Revenue Accrual represents the portion of the revenue requirement that will be collected in the subsequent year (January-May). Congestion Costs incurred versus costs recovered in rates from customers in distribution level rates are also deferred. Regional Network Service (RNS) is a new deferral incorporating the method of determining the RNS credit using an actual vs forecasted method.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes various items subject to reconciliation such as Unamortized Losses on Reacquired Debt in current, Electric Thermal Storage (ETS), CRM&B (Billing System Costs), Arrears Forgiveness Program, OPA Consulting Costs, Non-Wire Alternative Costs, Vegetation Management, Net Energy Billing Admin Costs and Pension Settlement.

Current and non-current regulatory liabilities at December 31, 2021 and 2020 consisted of:

As of December 31,	2021	2020
(Thousands)		
Current		
Accrued removal obligations	$ 2,251	$ 2,251
Transmission revenue reconciliation mechanism	9,117	5,580
Revenue decoupling mechanism	12,603	9,351
Tax Act - remeasurement	12,483	6,011
Other	1,458	942
Total current regulatory liabilities	**37,912**	**24,135**
Non-current		
Environmental remediation costs	795	1,453
Rate refund - FERC ROE proceeding	26,907	26,040
Accrued removal obligations	39,105	42,310
Tax Act - remeasurement	289,037	332,925
Other	764	500
Total non-current regulatory liabilities	**$ 356,608**	**$ 403,228**

Accrued removal obligations represent the differences between asset removal costs incurred and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

Rate refund - FERC ROE proceeding: see Note 2.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Tax Act - re-measurement represents the impact from re-measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases.

Transmission revenue reconciliation mechanism (ATU) reflects any differences in actual costs in the rate year from those used to set rates. The ATU is recovered over the subsequent June to May period. When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve-month period as the related revenues are collected (refunded).

Other includes various items subject to reconciliation such as Electric Lifeline Program (ELP), Vegetation Management, CRM&B (Billing System Costs) and Disconnect Notice Cost.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

CMP derives its revenue primarily from tariff-based sales of electricity service to customers in the Maine area with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. Maine state law prohibits the utility from providing the electricity commodity to customers. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as CMP delivers or sells the electricity or provides the transmission service.

CMP records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. CMP ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

CMP also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

Revenues disaggregated by major source for the year ended December 31, 2021 and 2020 are as follows:

Years Ended December 31,	2021	2020
(Thousands)		
Regulated operations – electricity	$ 922,320	$ 822,410
Other(a)	23,254	17,409
Revenue from contracts with customers	**945,574**	**839,819**
Leasing revenue	1,529	1,598
Alternative revenue programs	14,740	31,702
Other revenue	16,556	15,106
Total operating revenues	**$ 978,399**	**$ 888,225**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting CMP.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of our cash flows and the rates of return market participants would require in order to invest their capital in CMP. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

We had no impairment of goodwill in 2021 and 2020 as a result of our impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2021 or 2020 that required us to update the assessment.

The carrying amount of goodwill was $324.9 million at both December 31, 2021 and 2020, with no accumulated impairment losses and no changes during 2021 and 2020.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Current		
Federal	$ 10,095	$ 2,325
State	(3,370)	(3,505)
Current taxes charged to expense (benefit)	**6,725**	**(1,180)**
Deferred		
Federal	(284)	23,948
State	24,349	18,913
Deferred taxes charged to expense	**24,065**	**42,861**
Total Income Tax Expense	**$ 30,790**	**$ 41,681**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Tax expense at federal statutory rate	$ 44,872	$ 38,287
Depreciation/amortization and other plant differences not normalized	(11,196)	(4,932)
State taxe expense, net of federal benefit	16,573	12,172
Excess ADIT giveback	(18,609)	(6,017)
Other, net	(850)	2,171
Total Income Tax Expense	**$ 30,790**	**$ 41,681**

Income tax expense for the year ended December 31, 2021 was $14.1 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Depreciation, amortization and other plant differences not normalized, partially offset by state taxes. This resulted in an effective tax rate of 14.4%. Income tax expense for the year ended December 31, 2020 was $3.4 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, offset by a benefit in Depreciation, amortization and other plant differences not normalized. This resulted in an effective tax rate of 22.9%.

In 2021, CMP began refunding previously deferred Regional Transmission Excess ADITs and continued refunding previously deferred other Excess ADITs, established as a result of the 2017 Tax Act, pursuant to a regulatory order and as determined by the FERC, MPUC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2021 and 2020 consisted of:

December 31,		2021		2020
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	668,742	$	623,698
Unfunded future income taxes		40,992		42,538
Pension and other postretirement benefits		8,540		11,274
Regulatory liability due to "Tax Cuts and Jobs Act"		(83,491)		(95,087)
Derivative assets		—		—
Federal and state NOL's		(96)		(7,315)
Other		11,643		20,485
Total Non-current Deferred Income Tax Liabilities	**$**	**646,330**	**$**	**595,593**
Deferred tax assets	$	83,587	$	102,402
Deferred tax liabilities		729,917		697,995
Net Accumulated Deferred Income Tax Liabilities	**$**	**646,330**	**$**	**595,593**

CMP has gross Maine state net operating losses of $11.8 million for the year ended December 31, 2021. CMP had gross Maine state net operating losses of $122.9 million for the year ended December 31, 2020.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2021, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,		2021		2020
(Thousands)				
Beginning Balance	$	18,663	$	21,545
Reduction for tax positions related to prior years		(2,878)		(2,882)
Ending Balance	**$**	**15,785**	**$**	**18,663**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2021 or 2020.

Note 7. Non-current Debt

Long-term debt as of December 31, 2021 and 2020 consisted of:

As of December 31,		2021		2020	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2022-2045	$ 1,150,000	1.87%-5.68%	$ 1,100,000	1.87%-5.68%
Senior unsecured notes	2025-2037	140,000	5.375%-6.40%	140,000	5.375%-6.40%
Unamortized debt issuance costs and discount		(4,403)		(4,485)	
Total Debt		**1,285,597**		**1,235,515**	
Less: debt due within one year, included in current liabilities		124,578		149,549	
Total Non-current Debt		**$ 1,161,019**		**$ 1,085,966**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service.

On December 15, 2021, CMP issued $200 million aggregate prinicpal amount of first mortgage bonds maturing in 2031 at an interest rate of 2.05%.

On December 15, 2020, CMP issued $50 million aggregate principal amount of first mortgage bonds maturing in 2030 at an interest rate of 1.87%.

Long-term debt, including sinking fund obligations, due during the next five years consist of:

2022	2023	2024	2025	2026	Total
(Thousands)					
$ 124,578	$ —	$ —	$ 80,000	$ 80,000	$ 284,578

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2021 and 2020.

Note 8. Bank Loans and Other Borrowings

CMP had $1.1 million of notes payable at December 31, 2021 and $72.9 million at December 31, 2020. CMP funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the "Virtual Money Pool Agreement"), a bi-lateral intercompany credit agreement with Avangrid (the "Bi-Lateral Intercompany Facility") and a bank provided credit facility to which CMP is a party (the "AGR Credit Facility"), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP has a lending/borrowing limit of $100 million under this agreement. CMP had no debt outstanding under this agreement at December 31, 2021 and $42.1 million outstanding under this agreement at December 31, 2020.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP had $1.1 million outstanding under this agreement at December 31, 2021 and $30.8 million outstanding at December 31, 2020.

On November 23, 2021, Avangrid and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"),

CMP, The United Illuminating Company (“UI”), Connecticut Natural Gas Corporation (“CNG”), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company (“BGC”)) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the AGR Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million, UI has $250 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase Avangrid’s maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10 to 22.5 basis points. CMP had not borrowed under this agreement as of both December 31, 2021 and 2020.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.37 to 1.00 at December 31, 2021. We are not in default as of December 31, 2021.

Note 9. Redeemable Preferred Stock

We have redeemable preferred stock that contains a feature that could lead to potential redemption-triggering events that are not solely within our control.

At December 31, 2021 and 2020, our redeemable preferred stock was:

				Amount (Thousands)	
Series	**Par Value per Share**	**Redemption Price per Share**	**Shares Authorized and Outstanding(1)**	**2021**	**2020**
CMP, 6% Non-callable	$ 100	$ —	5,713	$ 571	$ 571
Total				**$ 571**	**$ 571**

(1) At December 31, 2021 CMP had $2,300,000 shares of $100 par value preferred stock authorized but unissued.

CMP Group owns 3,792 shares of the 5,713 shares outstanding.

Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to

62 years, some of which may include options to extend the leases for up to 10 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

For the Years Ended December 31,	2021	2020
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 342	$ 540
Interest on lease liabilities	6	190
Total finance lease cost	348	730
Operating lease cost	1,639	1,750
Short-term lease cost	33	60
Variable lease cost	56	62
Total lease cost	**$ 2,076**	**$ 2,602**

Balance sheet and other information for the years ended December 31, 2021 and 2020 was as follows:

As of December 31,	2021	2020
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 14,774	$ 15,549
Operating lease liabilities, current	1,161	1,146
Operating lease liabilities, long-term	14,791	15,204
Total operating lease liabilities	$ 15,952	$ 16,350
Finance Leases		
Other assets	$ 4,058	$ 4,400
Other current liabilities	—	267
Other non-current liabilities	—	(13)
Total finance lease liabilities	$ —	$ 254
Weighted-average Remaining Lease Term (years)		
Finance leases	—	0.25
Operating leases	18.71	19.76
Weighted-average Discount Rate		
Finance leases	—	27.44 %
Operating leases	3.84 %	4.00 %

For the years ended December 31, 2021 and 2020, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,		2021		2020
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	1,804	$	1,480
Operating cash flows from finance leases	$	6	$	190
Financing cash flows from finance leases	$	254	$	925
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	455	$	76

As of December 31, 2021, maturities of lease liabilities were as follows:

		Operating Leases
(Thousands)		
Year ending December 31,		
2022	$	1,303
2023		1,277
2024		1,262
2025		1,120
2026		1,039
Thereafter		17,603
Total lease payments		**23,604**
Less: imputed interest		(7,652)
Total	**$**	**15,952**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 11. Commitments and Contingent Liabilities

Power purchase contracts including non-utility generator

We recognized expense of approximately $29.8 million for non-utility generator power in 2021 and $19.3 million in 2020.

Note 12. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric service.

Waste sites

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at seven waste sites. The seven sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the seven sites, five sites are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and two sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $2.2 million related to the seven sites at December 31, 2021.

We have recorded an estimated liability of $2.3 million at December 31, 2021, related to four additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or are regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate the 11 total sites ranges from $3.6 million to $9.9 million as of December 31, 2021. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our three sites where gas was manufactured in the past. All three sites are part of Maine's Voluntary Response Action Program and two are on the Maine's Uncontrolled Sites Program.

Our estimate for all costs related to investigation and remediation of the three sites range from $0.2 million to $1.1 million at December 31, 2021. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $0.6 million and $0.7 million at December 31, 2021 and 2020, respectively. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis. We have received insurance settlements during the last two years, which we accounted for as reductions in our related regulatory asset.

Note 13. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

The financial instruments we hold or issue are not for trading or speculative purposes.

Cash flow hedging: Our fleet fuel hedges are designated as cash flow hedging instruments. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income (OCI), to the extent they are considered effective, and reclassify those gains or losses into earnings in the same period or periods during which the hedged transactions affect earnings.

Our derivatives designated as hedging instruments, which are other commodity contracts (fleet fuel), had a fair value of $0.1 million as of December 31, 2021 and are included in current assets. Our derivatives designated as hedging instruments had a fair value of $(0.1) million as of December 31, 2020, and are included in current liabilities.

The effect of hedging instruments on OCI and income for the years ended December 31, 2021 and 2020, respectively, consisted of:

Years Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified From Accumulated OCI into Income	(Loss) Gain Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2021				
Interest rate contracts	$ —	Interest expense	$ (181)	$ 46,347
Commodity contracts: Other	434	Other operating expenses	259	$ 486,685
Total	**$ 434**		**$ 78**	
2020				
Interest rate contracts	$ —	Interest expense	$ (181)	$ 46,148
Commodity contracts: Other	(358)	Other operating expenses	(341)	$ 443,678
Total	**$ (358)**		**$ (522)**	

The amount in AOCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $2.3 million for 2021 and $2.5 million for 2020. For the year ended December 31, 2021, we recorded $0.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $0.2 million of discontinued cash flow hedges in 2022.

At December 31, 2021, $0.1 million in gains are reported in OCI because the forecasted transaction is considered to be probable. We expect that those gains in OCI will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	**Mwhs**	**Dths**	**Gallons**
As of December 31, 2021			
2022	—	—	581,400
As of December 31, 2020			
2021	—	—	675,200

Note 14. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,491 million and $1,548 million as of December 31, 2021 and 2020, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2021 and 2020 consist of:

Description	Total	(Level 1)	(Level 2)	(Level 3)
(Thousands)				
2021				
Assets				
Derivatives	$ 38	$ —	$ —	$ 38
Total	**$ 38**	**$ —**	**$ —**	**$ 38**
2020				
Liabilities				
Derivatives	$ (137)	$ —	$ —	$ (137)
Total	**$ (137)**	**$ —**	**$ —**	**$ (137)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2021 and 2020. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Beginning balance	$ (137)	$ (120)
Total (losses) gains (realized/unrealized)		
Included in earnings	(259)	341
Included in other comprehensive income	434	(358)
Ending balance	**$ 38**	**$ (137)**

The amounts of realized and unrealized gain and loss included in earnings for the period (above) are reported in Operations and maintenance of the consolidated statements of income.

Note 15. Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss for the years ended December 31, 2021 and 2020 consisted of:

(Thousands)	Balance December 31, 2019	2020 Change	Balance December 31, 2020	2021 Change	Balance December 31, 2021
Amortization of pension cost for non-qualified plans, net of income tax expense of $607 for 2020(a) and $33 for 2021	$ (1,791)	$ (188)	$ (1,979)	$ 83	$ (1,896)
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) gain during period on derivatives qualified as hedges, net of income tax (benefit) expense of ($101) for 2020 and $231 for 2021		(257)		203	
Reclassification adjustment for loss (gain) included in net income, net of income tax expense (benefit) of $96 for 2020 and ($138) for 2021		245		(121)	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $51 for 2020 and $96 for 2021		130		85	
Net unrealized (loss) gain on derivatives qualified as hedges	(1,932)	118	(1,814)	167	(1,647)
Accumulated Other Comprehensive Loss	**$ (3,723)**	**$ (70)**	**$ (3,793)**	**$ 250**	**$ (3,543)**

(a) $607 tax expense in 2020 includes $490 adjustment related to prior periods.

No Accumulated Other Comprehensive Loss is attributable to the noncontrolling interest for the above periods.

Note 16. Post-Retirement and Similar Obligations

We have funded non-contributory defined benefit pension plans that cover all eligible employees. The plans provide defined benefits based on years of service and final average salary for employees hired before 2002. Most employees hired in 2002, or later based upon the plan, are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, we announced that we would discontinue, effective December 31, 2013, the cash balance accruals for all non-union employees covered under the cash balance plans or formula. At the same time, the plans were closed to newly-hired non-union employees. The plans had been closed to newly-hired union employees in prior years. CMP's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2014. Their earned balances will continue to accrue interest but will no longer be increased by a flat dollar amount or percentage of pay, as defined by the plan. Instead, they will receive a contribution to their account under their respective company’s defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution, depending on whether they are union or non-union employees, respectively.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $5.3 million for 2021 and $4.5 million for 2020.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our consolidated balance sheets, was $1.6 million and $1.7 million at December 31, 2021 and 2020, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 462,706**	**$ 441,533**	**$ 108,172**	**$ 102,653**
Service cost	6,101	8,005	626	571
Interest cost	11,603	12,665	2,402	2,912
Curtailments/settlements	(21,790)	—	—	—
Actuarial loss (gain)	(34,213)	26,842	(11,097)	8,536
Benefits paid	(16,984)	(26,339)	(6,079)	(6,500)
Benefit obligation as of December 31,	**$ 407,423**	**$ 462,706**	**$ 94,024**	**$ 108,172**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 354,910**	**$ 319,167**	**$ 34,465**	**$ 33,287**
Actual return on plan assets	32,230	42,082	3,509	4,008
Employer contributions	20,000	20,000	—	3,670
Curtailments/settlements	(21,790)	—	—	—
Benefits paid	(16,984)	(26,339)	(15,813)	(6,500)
Fair value of plan assets at December 31,	**$ 368,366**	**$ 354,910**	**$ 22,161**	**$ 34,465**
Funded status at December 31,	**$ (39,057)**	**$ (107,796)**	**$ (71,863)**	**$ (73,707)**

During 2021, the pension benefit obligation had an actuarial gain of $34.2 million, primarily due to a $24.1 million gain from increases in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2020, the pension benefit obligation had an actuarial loss of $26.8 million, primarily due to a $22.4 million loss from decreases in discount rates. There were no significant plan design changes in 2020. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized as of December 31, 2021 and 2020 consisted of:

As of December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Non-current liabilities	$ (39,057)	$ (107,796)	$ (71,863)	$ (73,707)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net loss	$ 101,256	$ 167,453	$ 22,071	$ 37,622
Prior service cost (credit)	$ —	$ —	$ (637)	$ (2,650)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $377.5 million and $426.8 million as of December 31, 2021 and 2020. Our postretirement benefits were partially funded at December 31, 2021 and 2020.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2021 and 2020. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,	2021	2020
(Thousands)		
Projected benefit obligation	$ 407,423	$ 462,706
Accumulated benefit obligation	$ 377,500	$ 426,816
Fair value of plan assets	$ 368,366	$ 354,910

As of December 31, 2021 and 2020, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2021 and 2020 consisted of:

For the years ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 6,101	$ 8,005	$ 626	$ 571
Interest cost	11,603	12,665	2,402	2,912
Expected return on plan assets	(23,532)	(23,035)	(1,768)	(1,979)
Amortization of prior service cost (benefit)	—	—	(2,013)	(2,013)
Settlement charge	5,421	—	—	—
Amortization of net loss	17,866	16,843	2,713	2,230
Net Periodic Benefit Cost	**$ 17,459**	**$ 14,478**	**$ 1,960**	**$ 1,721**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net loss (gain)	$ (42,911)	$ 7,796	$ (12,837)	$ 6,507
Amortization of net loss	(17,866)	(16,843)	(2,713)	(2,230)
Settlements	(5,421)	—	—	—
Amortization of prior service (cost) benefit	—	—	2,013	2,013
Total Other Changes	**(66,198)**	**(9,047)**	**(13,537)**	**6,290**
Total Recognized	**$ (48,739)**	**$ 5,431**	**$ (11,577)**	**$ 8,011**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate	2.96% / 3.05% union	2.56%	2.74 %	2.29 %
Rate of compensation increase	Age-Related Rates / 3.50% union	Age-Related Rates / 3.50% union	3.50 %	3.50 %
Interest crediting rate	2.00% non-union/ 4.50% union	2.00% non-union/ 4.50% union	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rates by developing yield curves derived from a portfolio of high grade non-callable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	2020	Postretirement Benefits 2021	2020
Discount rate	2.56 %	2.93 %	2.29 %	2.93 %
Expected long-term return on plan assets	7.00 %	7.30 %	5.13	—
Expected long-term return on plan assets - non-taxable trust	—	—	—	6.40 %
Expected long-term return on plan assets - taxable trust	—	—	—	4.20 %
Rate of compensation increase (Union/Non-Union)	Age-Related Rates / 3.50% union	Age-Related Rates	Age-Related Rates / 3.50% union	Age-Related Rates

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses using the standard amortization methodology under which amounts in excess of 10% of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	2021	2020
Health care cost trend rate assumed for next year	6.50%/7.25%	6.75%/7.50%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2029/2027	2029/2027

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We expect to contribute $20 million to our pension plans during 2022. We do not expect to contribute to our other postretirement benefit plans during 2022.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2021 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2022	$ 18,869	$ 6,220	$ —
2023	$ 19,529	$ 6,153	$ —
2024	$ 20,090	$ 6,098	$ —
2025	$ 20,985	$ 6,020	$ —
2026	$ 21,401	$ 5,955	$ —
2027 - 2031	$ 114,489	$ 27,904	$ 1

Plan assets

Our pension benefits plan assets are held in a master trust providing for a single trustee/ custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We currently have target allocations ranging from 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 11,350	$ 1,663	$ 9,687	$ —
U.S. government securities	21,896	21,896	—	—
Common stocks	15,913	15,913	—	—
Registered investment companies	34,079	34,079	—	—
Corporate bonds	97,111	—	97,111	—
Preferred stocks	104	104	—	—
Common collective trusts	125,099	—	125,099	—
Other, principally annuity, fixed income	2,687	1	2,686	—
	$ 308,239	**$ 73,656**	**$ 234,583**	**$ —**
Other investments measured at net asset value	60,127			
Total	**$ 368,366**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 15,726	$ 12	$ 15,714	$ —
U.S. government securities	20,317	20,311	6	—
Common stocks	12,411	12,411	—	—
Registered investment companies	34,487	34,487	—	—
Corporate bonds	81,500	—	81,500	—
Preferred stocks	113	113	—	—
Common collective trusts	111,139	—	111,139	—
Other, principally annuity, fixed income	7,834	728	7,106	—
	$ 283,527	**$ 68,062**	**$ 215,465**	**$ —**
Other investments measured at net asset value	71,383			
Total	**$ 354,910**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Substantially all of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49%-69% for equity securities and 31%-51% for fixed income investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 1,456	$ 32	$ 1,424	$ —
U.S. government securities	401	401	—	—
Common stocks	362	362	—	—
Registered investment companies	15,081	15,081	—	—
Corporate bonds	1,582	—	1,582	—
Preferred stocks	2	2	—	—
Common collective trusts	2,336	—	2,336	—
Other, principally annuity, fixed income	52	—	52	—
	$ 21,272	**$ 15,878**	**$ 5,394**	**$ —**
Other investments measured at net asset value	889			
Total	**$ 22,161**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 1,125	$ —	$ 1,125	$ —
U.S. government securities	101	101	—	—
Common stocks	62	62	—	—
Registered investment companies	31,863	31,863	—	—
Corporate bonds	1	1	—	—
Preferred stocks	405	—	405	—
Common collective trusts	550	—	550	—
Other, principally annuity, fixed income	3	4	(1)	—
	$ 34,110	**$ 32,031**	**$ 2,079**	**$ —**
Other investments measured at net asset value	355			
Total	**$ 34,465**			

Valuation techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks and registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2021 and 2020.

Note 17. Other Income and Other Deductions

Other Income and Other Deductions for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Gain on sale of property	$ —	$ 559
Interest and dividends income	3,308	251
Allowance for funds used during construction	15,136	11,532
Carrying costs on regulatory assets	473	3,688
Equity earnings	55	53
Miscellaneous	225	286
Total other income	**$ 19,197**	**$ 16,369**
Pension non-service components	$ (12,152)	$ (7,158)
Miscellaneous	(5,203)	(8,741)
Total other deductions	**$ (17,355)**	**$ (15,899)**

Note 18. Related Party Transactions

Certain Networks subsidiaries, including CMP, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

AGR, through its affiliates, provides administrative and management services to Networks operating utilities, including CMP, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to CMP by AGR and its affiliates was $42.3 million and $46.3 million for 2021 and 2020, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $8.4 million in 2021 and $7.8 million in 2020. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by CMP to AGR and its subsidiaries were approximately $5.1 million for 2021 and $6.0 million for 2020. All charges for services are at cost. All of the charges associated with services provided are recorded as revenues to offset other operating expenses on the financial statements.

The balance in accounts payable to affiliates of $38.3 million at December 31, 2021 and the balance of $8.1 million at December 31, 2020 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $63.9 million at December 31, 2021 is mostly receivable from New England Clean Energy Connect. The balance in accounts receivable from affiliates of $1.4 million at December 31, 2020 is receivable from various companies.

There were no notes receivable from affiliates at December 31, 2021 and December 31, 2020. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

On January 4, 2021, in connection with certain stipulation agreements (Stipulations), CMP transferred the NECEC project as disclosed in Note 1 to NECEC Transmission LLC pursuant to the terms of a transfer agreement dated November 3, 2020. At that time, NECEC Transmission LLC reimbursed to CMP approximately $101 million in construction and other costs CMP had incurred in connection with the NECEC through the date of transfer.

As consideration for the transfer of the NECEC project, NECEC Transmission LLC agreed to pay CMP the sum total of $60 million, payable in one hundred and sixty equal installments of $375,000 each, due the first business day of each January, April, July and October, to be included in CMP's NECEC Rate Relief Fund as established by the Stipulations. CMP received $1.5 million in such payments from NECEC Transmission LLC in 2021. Similarly and in connection with the Stipulations, CMP will receive $80 million, payable in one hundred and sixty equal installments of $500,000, due the first business day of each January, April, July and October, from funding provided by H.Q. Energy Services (U.S.) Inc., an unaffiliated entity, which will be included in CMP's NECEC Rate Relief Fund. Pursuant to the terms of the Stipulations, all these payments were suspended in December 2021 following the stoppage of construction of the NECEC project. Payments will remain suspended until construction resumes. In addition, as of December 31, 2021, CMP accrued $61.4 million of contributions in aid of construction within Construction work in progress related to NECEC Transmission LLC paying for CMP-owned assets which CMP is improving related to the NECEC interconnection. The accrued amount was paid to CMP in January 2022.

Note 19. Subsequent Events

The company has performed a review of subsequent events through March 24, 2022, which is the date these consolidated financial statements were available to be issued.

New York State Electric & Gas Corporation

Financial Statements

As of and for the Years Ended December 31, 2021 and 2020

New York State Electric & Gas Corporation

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

Shareholders and The Board of Directors
New York State Electric & Gas Corporation:

Opinion

We have audited the financial statements of New York State Electric & Gas Corporation (the Company), which comprise the balance sheets as of December 31, 2021 and 2020, and the related statements of income, comprehensive income, changes in common stock equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

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

Responsibilities of Management for the Financial Statements

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

KPMG LLP

New York, New York
March 22, 2022

New York State Electric & Gas Corporation
Statements of Income

Years Ended December 31,		2021		2020
(Thousands)				
Operating Revenues	$	**1,804,453**	$	**1,564,241**
Operating Expenses				
Electricity purchased		396,439		268,829
Natural gas purchased		114,942		81,324
Operations and maintenance		756,212		705,205
Depreciation and amortization		172,600		159,438
Taxes other than income taxes, net		164,777		157,657
Total Operating Expenses		**1,604,970**		**1,372,453**
Operating Income		**199,483**		**191,788**
Other income		34,035		33,664
Other deductions		(15,703)		(26,365)
Interest expense, net of capitalization		(54,373)		(65,777)
Income Before Income Tax		**163,442**		**133,310**
Income tax expense		9,305		3,362
Net Income	$	**154,137**	$	**129,948**

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

New York State Electric & Gas Corporation
Statements of Comprehensive Income

Years Ended December 31,		2021		2020
(Thousands)				
Net Income	$	**154,137**	$	**129,948**
Other Comprehensive Income (Loss), Net of Tax				
Amortization of pension cost for non-qualified plans, net of income tax		108		(459)
Unrealized gain (loss) during the year on derivatives qualifying as cash flow hedges, net of income tax		486		(92)
Reclassification to net income of (gain) loss on settled cash flow commodity hedges, net of income tax		(304)		85
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax		63		14
Total Other Comprehensive Income (Loss), Net of Tax		**353**		**(452)**
Comprehensive Income	$	**154,490**	$	**129,496**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 1	$ 266
Accounts receivable and unbilled revenues, net	301,099	254,762
Accounts receivable from affiliates	2,415	4,790
Notes receivable from affiliates	—	7,150
Fuel and natural gas in storage, at average cost	22,100	10,181
Materials and supplies	25,031	21,231
Broker margin accounts	12,043	6,521
Derivative assets	7,977	—
Prepaid property taxes	38,090	38,109
Other current assets	3,318	5,272
Regulatory assets	112,422	98,096
Total Current Assets	**524,496**	**446,378**
Utility plant, at original cost	7,383,849	6,816,853
Less accumulated depreciation	(2,339,717)	(2,263,857)
Net Utility Plant in Service	**5,044,132**	**4,552,996**
Construction work in progress	597,562	531,695
Total Utility Plant	**5,641,694**	**5,084,691**
Operating lease right-of-use assets	8,345	8,896
Other property and investments	10,561	10,447
Regulatory and Other Assets		
Regulatory assets	742,160	867,559
Other	42,947	41,417
Total Regulatory and Other Assets	**785,107**	**908,976**
Total Assets	**$ 6,970,203**	**$ 6,459,388**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,		2021		2020
(Thousands, except share information)				
Liabilities				
Current Liabilities				
Current portion of long-term debt	$	73,083	$	—
Notes payable to affiliates		79,800		—
Accounts payable and accrued liabilities		445,640		413,454
Accounts payable to affiliates		100,067		33,989
Interest accrued		13,171		11,233
Taxes accrued		39,508		6,284
Operating lease liabilities		915		1,015
Derivative liabilities		27		270
Environmental remediation costs		27,657		31,695
Customer deposits		19,810		13,978
Regulatory liabilities		106,440		107,565
Other		100,883		72,922
Total Current Liabilities		**1,007,001**		**692,405**
Regulatory and Other Liabilities				
Regulatory liabilities		1,074,886		1,144,783
Other Non-current Liabilities				
Deferred income taxes		664,095		595,376
Pension and other postretirement		143,562		261,218
Operating lease liabilities		8,294		8,659
Asset retirement obligation		11,583		12,284
Environmental remediation costs		64,832		78,661
Other		27,577		40,547
Total Regulatory and Other Liabilities		**1,994,829**		**2,141,528**
Non-current debt		1,997,311		1,724,239
Total Liabilities		**4,999,141**		**4,558,172**
Commitments and Contingencies				
Common Stock Equity				
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 64,508,477 shares outstanding at December 31, 2021 and 2020)		430,057		430,057
Additional paid-in capital		1,054,042		868,686
Retained earnings		488,132		603,995
Accumulated other comprehensive loss		(1,169)		(1,522)
Total Common Stock Equity		**1,971,062**		**1,901,216**
Total Liabilities and Equity	**$**	**6,970,203**	**$**	**6,459,388**

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

New York State Electric & Gas Corporation
Statements of Cash Flows

Years Ended December 31,	2021	2020
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 154,137**	**$ 129,948**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	172,600	159,438
Regulatory assets/liabilities amortization	(11,984)	9,174
Regulatory assets/liabilities carrying cost	(568)	2,402
Amortization of debt issuance costs	808	985
Deferred taxes	20,345	14,549
Pension cost	33,795	51,064
Stock-based compensation	451	312
Accretion expenses	648	685
Gain from disposal of property	(675)	(847)
Other non-cash items	(54,374)	(50,165)
Changes in assets and liabilities		
Accounts receivable, from affiliates, and unbilled revenues	(43,962)	7,095
Inventories	(15,719)	1,096
Accounts payable, to affiliates, and accrued liabilities	148,389	3,702
Taxes accrued	33,223	25,789
Other assets/liabilities	73,311	30,941
Regulatory assets/liabilities	(110,284)	(134,585)
Net Cash Provided by Operating Activities	**400,141**	**251,583**
Cash Flow from Investing Activities:		
Capital expenditures	(799,032)	(693,054)
Contributions in aid of construction	48,072	21,309
Proceeds from sale of property, plant and equipment	2,178	2,652
Notes receivable from affiliates	7,150	(7,150)
Net Cash Used in Investing Activities	**(741,632)**	**(676,243)**
Cash Flow from Financing Activities:		
Non-current debt issuance	346,807	198,006
Repayments of finance leases	(381)	(1,826)
Notes payable to affiliates	79,800	(71,255)
Capital contribution	185,000	400,000
Dividends paid	(270,000)	(100,000)
Net Cash Provided by Financing Activities	**341,226**	**424,925**
Net (Decrease) Increase in Cash and Cash Equivalents	**(265)**	**265**
Cash and Cash Equivalents, Beginning of Year	**266**	**1**
Cash and Cash Equivalents, End of Year	**$ 1**	**$ 266**

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

New York State Electric & Gas Corporation
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of Shares (*)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity
Balance, December 31, 2019	**64,508,477**	**$ 430,057**	**$ 468,459**	**$ 574,153**	**$ (1,070)**	**$ 1,471,599**
Adoption of accounting standards	—	—	—	(106)	—	(106)
Net income	—	—	—	129,948	—	129,948
Other comprehensive loss, net of tax	—	—	—	—	(452)	(452)
Comprehensive income						129,496
Stock-based compensation	—	—	227	—	—	227
Common stock dividends	—	—	—	(100,000)	—	(100,000)
Capital contribution	—	—	400,000	—	—	400,000
Balance, December 31, 2020	**64,508,477**	**430,057**	**868,686**	**603,995**	**(1,522)**	**1,901,216**
Net income	—	—	—	154,137	—	154,137
Other comprehensive income, net of tax	—	—	—	—	353	353
Comprehensive income						154,490
Stock-based compensation	—	—	356	—	—	356
Common stock dividends	—	—	—	(270,000)	—	(270,000)
Capital contribution	—	—	185,000	—	—	185,000
Balance, December 31, 2021	**64,508,477**	**$ 430,057**	**$ 1,054,042**	**$ 488,132**	**$ (1,169)**	**$ 1,971,062**

(*) Par value of share amounts is 6.66 2/3

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

Notes to Financial Statements

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

Background and nature of operations: New York State Electric & Gas Corporation (NYSEG, the company, we, our, us) conducts regulated electricity transmission and distribution operations and regulated natural gas transportation, storage and distribution operations in upstate New York. It also generates electricity, primarily from its several hydroelectric stations. NYSEG serves approximately 914,000 electricity and 272,000 natural gas customers as of December 31, 2021, in its service territory of approximately 20,000 square miles, which is located in the central, eastern and western parts of the state of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

NYSEG is a subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Basis of presentation*:** The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

Significant Accounting Policies: We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our financial statements:

***Revenue recognition*:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

***Regulatory accounting*:** We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

***Utility plant*:** We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.3% of average depreciable property for 2021 and 2.3% for 2020. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 7 to 27 years. Capitalized software costs were approximately $254.9 million as of December 31, 2021 and $223.4 million as of December 31, 2020. Depreciation expense was $161.4 million in 2021 and $149.5 million in 2020. Amortization of capitalized software was $11.2 million in 2021 and $10 million in 2020.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	**Estimated useful life range (years)**	**2021**	**2020**
(Thousands)			
Electric	2-80	$ 5,252,740	$ 4,912,866
Natural Gas	2-75	1,260,361	1,175,900
Common	7-70	870,748	728,087
Total Utility Plant in Service		**7,383,849**	**6,816,853**
Total accumulated depreciation		(2,339,717)	(2,263,857)
Total Net Utility Plant in Service		**5,044,132**	**4,552,996**
Construction work in progress		597,562	531,695
Total Utility Plant		**$ 5,641,694**	**$ 5,084,691**

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset’s fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant’s view of the exit price of the asset.

***Fair value measurement*:** 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant’s ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

***Derivatives and hedge accounting*:** Derivatives are recognized on our balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs, which we present in the same income statement line item as the earnings effect of the hedged item. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. We record changes in the fair value of electric and natural gas hedge contracts to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

***Cash and cash equivalents*:** Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our balance sheets. We report changes in book overdrafts in the operating activities section of the statements of cash flows.

Statements of cash flows: Supplemental disclosure of cash flow information is as follows:

		2021		2020
(Thousands)				
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	47,314	$	47,163
Income taxes refunded, net	$	(36,996)	$	(35,236)

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $8.8 million in 2021 and in $7.9 million in 2020. Accrued liabilities for utility plant additions were $6.6 million in 2021 and $52.1 million in 2020.

Broker margin accounts: We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. We show the amount reflecting those activities as broker margin accounts on our balance sheets.

***Trade receivables and unbilled revenues, net*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing trade receivables, determined based on experience for each service region. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $101 million for 2021 and $82.1 million for 2020, and are shown net of an allowance for credit losses at December 31 of $49.3 million for 2021 and $35.8 million for 2020. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $20.7 million in 2021 and $18.4 million in 2020.

Trade receivables include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments without interest over an extended period of time, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $14.6 million for 2021 and $17.7 million for 2020. DPA receivable balances at December 31 were $23.4 million for 2021 and $25.1 million for 2020.

Debentures, bonds and bank borrowings: We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our balance sheets.

Inventory*:* Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our balance sheets within “Fuel and natural gas in storage.”

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within “Materials and supplies.” We combine inventory items for the statement of cash flows presentation purposes.

In addition, stand-alone renewable energy credits that are generated or purchased and held for sale are recorded at the lower of cost or net realizable value and are reported on our balance sheets within “Materials and supplies”.

Government grants: We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in the period in which we incur the expenses.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them into earnings when revenue recognition criteria are met.

Notes to Financial Statements

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl-contaminated equipment, gas pipeline and cast iron gas mains and electricity generation facilities. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2021 and 2020.

Years ended December 31,	**2021**	**2020**
(Thousands)		
ARO, beginning of year	$ 12,284	$ 12,928
Liabilities settled during the year	(1,349)	(1,329)
Accretion expense	648	685
ARO, end of year	**$ 11,583**	**$ 12,284**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

***Accrued removal obligations*:** We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

***Environmental remediation liability*:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2053.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the NYPSC. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes**:** AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, NYSEG settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax payable to AGR is $31.9 million and $3.1 million at December 31, 2021 and 2020, respectively.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2021 and 2020.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current on our balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in “Taxes other than income taxes” and “Taxes accrued” in our financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in our statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Limited voting junior preferred stock: We have a class of preferred stock having one share and a par value of $1, which is issued and outstanding and has voting authority only with respect to whether NYSEG may file a voluntary bankruptcy petition.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation; (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments; and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers’ application of income-tax related guidance and simplify U. S. GAAP for: (1) franchise taxes that are partially based on income; (2) transactions with a government that result in a step up in the tax basis of goodwill; (3) separate financial statements of legal entities that are not subject to tax; and (4) enacted changes in tax laws in interim periods. We adopted the amendments effective January 1, 2021, with no material effect to our results of operations, financial position, cash flows and disclosures. We are applying the amendments on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment requirement.

(b) Improvements to lessor accounting for certain leases with variable lease payments

In July 2021, the FASB issued amendments to make targeted improvements to ASC 842 for lessor's accounting for certain leases with variable lease payments, which affect lease classification. The amendments require a lessor to classify and account for a lease with variable lease payments as an operating lease if (a) the lease would have been classified as a sales-type lease or a direct financing lease and (b) the lessor would have otherwise recognized a day-one loss. The amendments are effective for fiscal years beginning after December 15, 2021, for all entities, and interim periods within those fiscal years for public business entities, with early application permitted. We have elected to early apply the amendments effective October 1, 2021, and apply the amendments prospectively to leases that commence or are modified on or after that date. Our adoption does not materially affect our results of operations, financial position and cash flows.

(c) Accounting for revenue contracts with customers acquired in a business combination

In October 2021, the FASB issued amendments related to the accounting for revenue contracts acquired in a business combination. The amendments require an entity (acquirer) to recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606, Revenue from Contracts with Customers. At the acquisition date, an acquirer should account for the related revenue contract in accordance with ASC 606 as if it had originated the contracts. Generally, this should result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree's financial statements. The amendments also provide certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. For public business entities, the amendments are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The amendments should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted. We have elected to early apply the amendments effective October 1, 2021. Our adoption did not materially affect our results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2021, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments were effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Our prospective adoption of ASC 848 on January 1, 2022 will not materially affect our results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

In November 2021, the FASB issued amendments that apply to business entities (all entities except specified not-for-profit entities and employee benefit plans) that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance (such as a grant model within International Accounting Standards 20 Accounting for Government Grants and Disclosure of Government Assistance, or ASC Subtopic 958-605, Not-For-Profit Entities—Revenue Recognition). Government assistance can include tax credits (excluding transactions within the scope of Topic 740, Income Taxes), cash grants, grants of other assets, and project grants. Often, government assistance is provided to an entity for a particular purpose, and the entity promises to take specific actions. Transactions with a government, as used in ASC 832, Government Assistance, include assistance administered by domestic, foreign, local (city, town, county, municipal), regional (state, provincial, territorial), and national (federal) governments and entities related to those governments. The amendments require annual disclosures in notes to financial statements about transactions with a government as follows: (1) information about the nature of the transactions and the related accounting policy used to account for the transactions, (2) the line items on the balance sheet and income statement affected by the transactions, and the amounts applicable to each financial statement line item, and (3) significant terms and conditions of the transactions, including commitments and contingencies. For entities within scope the amendments are effective for annual periods beginning after December 15, 2021, with early application permitted. The amendments are to be applied either (1) prospectively to transactions within the scope of the amendments that are reflected in financial statements at the date of initial application and new transactions that are entered into after the date of initial application or (2) retrospectively to those transactions. Our adoption of the amendments on January 1, 2022 will not materially affect our disclosures.

Use of estimates and assumptions: The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) earnings sharing mechanism (ESM); (9) environmental remediation liabilities; (10) pension and other postretirement employee benefits (OPEB); (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 75% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the New York State Public Service Commission (NYPSC). The tariffs applied to regulated activities are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all of our operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity (ROE).

Energy costs that are set on the New York wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred is offset by applying reconciliation procedures that result in either immediate or deferred tariff adjustments. Reconciliation procedures apply to other costs, which are in many cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers. Any revenues that allow us to exceed target returns, usually the result of better than expected cost efficiency, are generally shared with customers, resulting in future tariff reductions.

NYSEG Rate Plan

On May 20, 2019, NYSEG filed rate cases requesting increases in delivery revenues for both its electric and gas businesses. Other parties to the rate cases filed direct testimony on September 20, 2019, and NYSEG filed rebuttal testimony on October 15, 2019. The Administrative Law Judges in the cases agreed to a series of extensions of the litigation schedule to allow the Company, the Department of Public Service Staff (DPS Staff), and other parties to enter into and conduct settlement discussions. A Joint Proposal for a three year rate plan term was filed on June 22, 2020. A modified Joint Proposal was approved by the NYPSC on November 19, 2020, which included modifications to the electric business proposed rate increases to limit the projected total bill increases to 2% per year in consideration of the current COVID-driven economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The approved Joint Proposal includes several COVID-19 provisions, including the provision of up to $16.5 million in bill credits for the Company's most vulnerable residential and small business customers. The Joint Proposal bases delivery revenues on an 8.80% ROE and 48% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50%. The approved Joint Proposal was signed in whole or in part by more than 20 parties, and includes delivery rate increases (excluding the impact of moving energy efficiency costs from a surcharge to delivery rates) as summarized below:

	May 1, 2020		May 1, 2021		May 1, 2022	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$34.3	4.6%	$45.6	5.9%	$36.0	4.2%
Gas	$0.0	0.0%	$1.6	0.8%	$3.3	1.6%

The approved Joint Proposal also reflects increased distribution vegetation management, investments in aging infrastructure, the implementation of Advanced Metering Infrastructure (AMI), and increases in the Company's workforce. The approved Joint Proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $227 million, of which $194 million will be amortized over ten years and the remaining $33 million will be amortized over five years. The approved Joint Proposal also continued reserve accounting for qualifying Major Storms ($25.6 million annually). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds for each storm event.

The approved Joint Proposal maintained electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The Proposal also maintained certain gas safety performance measures at the company, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The approved Joint Proposal established threshold performance levels for designated aspects of customer service quality and continues bill reduction and arrears forgiveness Low Income Programs. REV-related incremental costs and fees will be included in the revenue adjustment mechanism (RAM) to the extent cost recovery is not provided for elsewhere. Under the approved Joint Proposal, NYSEG continues the RAM, which is applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; (5) COVID-19 bill credits; (6) certain Electric Vehicle program costs; and (7) Energy Efficiency and Heat Pump program costs in excess of what is included in delivery rates.

The Proposal provided for partial or full reconciliation of certain expenses including, but not limited to: pension and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; Major Storms; nuclear electric insurance limited credits; economic development; and Low Income Programs. The Proposal also includes downward-only Net Plant reconciliations. In addition, the Proposal included downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provided that we continue the electric revenue decoupling mechanisms (RDM) on a total revenue per class basis and modify the gas RDMs to a total revenue per class basis instead of the previous revenue per customer basis.

Reforming the Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV, which is a wide-ranging initiative to reform New York State's energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV and its related proceedings have and will continue to propose regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

In 2015, the NYPSC issued an order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016, followed by bi-annual updates. The companies filed the initial DSIP, which also included information regarding the potential deployment of AMI across its entire service territory. The companies filed their required bi-annual updates of the DSIP on July 31, 2018 and June 30, 2020. The next bi-annual update is scheduled for June 2022.

Other various proceedings have also been initiated by the NYPSC which are REV-related, and each proceeding has its own schedule. These proceedings include the Clean Energy Standard, Value of Distributed Energy Resources (VDER) and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all load serving entities were ordered to begin payments to New York State Energy Research and Development Authority (NYSERDA) for Renewable Energy Credits (RECs) and Zero Emissions Credits (ZECs) beginning in 2017. NYSEG and RG&E collect costs associated with RECs and ZECs through electric supply charges. A separate Offshore Wind proceeding was ordered by the NYPSC in July 2018 setting a goal of 2,400 MW of offshore wind capacity in New York State by 2030. Initial procurement solicitations by NYSERDA in 2018 and 2019 secured 1,696 MW of offshore wind. On January 28, 2020, NYSERDA filed a petition seeking authorization to conduct an additional procurement in 2020 for 1,000 MW or more of offshore wind, with the flexibility to evaluate a range of bids for up to 2,500 MW In an order issued April 23, 2020, the Commission authorized NYSERDA to issue an additional offshore wind solicitation in 2020 for 1,000 MW or more.

A Track 2 order was issued in May 2016, and included guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections, and Clean Air. A collaborative process to review the companies' petition began in the first quarter of 2017 and was suspended in the third quarter of 2017. A proposal for EAMs was included in the companies' May 20, 2019 rate filing and is reflected in the recently approved Rate Plan.

In March, 2017, the NYPSC issued three separate REV-related orders. The three orders involve: 1) modifications to the electric utilities' proposed interconnection EAM framework; 2) further DSIP requirements, including the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at NYSEG by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of VDER. In September 2017, the NYPSC issued an order related to VDER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing. NYSEG submitted biannual updates of the DSIP on July 31, 2018 and June 30, 2020 consistent with guidance received from the NYPSC. NYSEG has participated with the other NY state electric utilities in jointly filing updates to the interconnection earnings adjustment mechanism, has implemented two energy storage projects, and has participated with the other NY state electric utilities in the VDER transition effort, including tariff updates and application of VDER principles.

The March 2017 Order in the VDER proceeding approved a transition from traditional Net Energy Metering (NEM) towards a more values-based approach (Value Stack) for compensating Distributed Energy Resources (DER). The March 2017 Order approved an interim methodology for more precise DER valuation and compensation for NEM-eligible technologies. The interim methodology approved by the NYPSC provided for a market transition consistent with the principles of gradualism and predictability and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceeding. Phase Two would encompass improvements to the interim methodology established in Phase One, seek to expand Value Stack eligibility to technologies not included in Phase One, and review rate designs for mass market (i.e., residential and small non-residential) on-site DERs whose project would be interconnected after January 1, 2020. Working groups were established for further discussions regarding Value Stack, Rate Design and Low Income. The working groups met toward the latter half of 2017 and all of 2018 to discuss, review and analyze several issues regarding each subject. The working groups culminated with a series of whitepapers developed by DPS Staff addressing: a) Standby and Buyback Service Rate Design, b) Future Value Stack Compensation, and c) Capacity Value Compensation. The whitepapers were submitted between December 12 and December 14, 2018 in the VDER proceeding.

The March 2017 Order stated that should a new compensation methodology not be in place by January 1, 2020, mass market projects put into service after that date would receive NEM compensation only until the new compensation methodology is developed and implemented and would then be transferred to the new compensation methodology. On December 9, 2019, DPS Staff filed a whitepaper on rate design for mass market NEM successor tariffs. DPS Staff recommended the continuation of NEM as a compensation mechanism for all eligible mass market and commercial DER projects under 750 kW. Staff also proposed that these projects should be eligible for the range of options currently provided in delivery rates. For projects with load profiles or expertise that may benefit from time-varying price signals, projects would have the option to forgo the use of standard delivery rates and instead utilize more sophisticated time-of-use (TOU) or new mass market standby rates, coupled with a modest charge to collect public benefit funds that are otherwise avoided by using NEM. On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022 and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 shall be charged a monthly per kW fee based on the nameplate rating of the DER. Draft tariff leaves implementing the Commission's Order and proposed CBC calculations were filed on November 1, 2020, and a technical conference was held on March 25, 2021 to review the utilities' calculations. A final Commission Order was issued on August 13, 2021 implementing the CBC effective January 1, 2022 for new mass market net metering customers.

On April 18, 2019, the Commission issued an Order on Future Value Stack Compensation and Capacity Value Compensation. The Order established a new Community Credit in place of the Market Transition Credit for certain CDG projects in NYSEG's and RG&E's service territories and expanded eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower. The changes became effective on June 1, 2019. On December 12, 2019, the NYPSC issued an Order Regarding Consolidated Billing For Community Distributed Generation. This Order led to CDG subscription charges being on the NYSEG bill along with the CDG subscription credits, resulting in easier billing for customers and lower billing and service costs for CDG Hosts. Also on December 12, 2019, the NYPSC issued an Order on Value Stack Compensation for High-Capacity-Factor Resources, modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding Value Stack Compensation. The Order directed National Grid, NYSEG, and RGE to reallocate capacity from closed tranches where available capacity remained due to projects being canceled since the issuance of the VDER Compensation Order, and to assign that capacity to a new Community Credit Tranche with compensation at 2 cents per kWh. The utilities must also continue to reallocate capacity to this new Tranche for the next six months when there are cancellations of projects that have received a Market Transition Credit or Community Credit allocation. The new provisions per the March 19, 2020 Order became effective May 1, 2020. As eligible projects are interconnected, each project will receive MTC or Community Credit compensation for kWh produced, and the dollars provided to each project for this compensation will ultimately be collected from customers in a future surcharge.

The April 18, 2019 Order also initiated a new proceeding to examine utilities' marginal cost of service studies. An initial meeting in that proceeding was held on June 28, 2019, during which the utilities explained their various marginal cost methodologies. DPS Staff will develop a whitepaper addressing the utilities' marginal cost studies with recommendations on how such studies shall be subsequently performed. To aid in the development of the whitepaper, Staff requested preliminary comments from stakeholders by November 25, 2019, and additional information from the Utilities in February 2020 regarding their marginal cost methodologies. At this time it is not known when the DPS Staff whitepaper on marginal cost methodologies will be issued.

On May 16, 2019, the Commission issued an Order on Standby and Buyback Service and Establishing Optional Demand Rates. The Order expands the availability of demand rates based on standby service rate design principles by requiring utilities to file tariffs to provide opt-in eligibility for all customers, including mass market (i.e., residential), to a demand-based rate option, irrespective of whether customers have on-site DERs. The availability of existing standby rates was expanded to all current demand-billed customers on an optional basis beginning July 1, 2019. Optional standby rates for mass market customers will be made available in the near future. NYSEG filed draft tariffs on September 23, 2019 as required, with further analysis and discussion regarding approval and implementation of the optional rates occurring through the Rate Design Working Group of the VDER proceeding. On November 25, 2020 DPS Staff, jointly with

NYSERDA, issued a whitepaper on further recommendations regarding standby and buyback rates that were based on the electric utilities' September 23, 2019 filings. Comments on the recommendations in the whitepaper were submitted on March 8, 2021, and reply comments were submitted on April 12, 2021. A technical conference was held on July 22, 2021, and an additional comment period was established for August 20, 2021. A Commission Order is expected in 2022.

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited customers. Stakeholders subsequently requested residential customers be permitted to participate as remote crediting satellites and the frequency of credit allocation and adding/removing satellites be increased to allow for monthly changes rather than annual changes only. Tariffs were filed on August 16, 2021, becoming effective on September 1, 2021.The result of this Order reshaped an existing program and the impact to the Companies should be minimal.

On April 24, 2018, the Commission instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the adoption of electric vehicles and expansion of electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, and subsequently clarified its Order on July 12, 2019 and March 3, 2020. A Whitepaper was issued by DPS Staff on January 13, 2020, proposing a make-ready infrastructure program with a budget estimated at $582 million. An order in this proceeding was issued on July 16, 2020 approving a $700 million statewide program (NYSEG and RG&E combined share is approximately $118 million) funded by customers to accelerate the deployment of electric vehicle charging stations in an effort to increase the number of electric vehicles.

On February 11, 2021, the Commission issued an Order to implement an Integrated Energy Data Resource platform, where NYSERDA was designated as the Program Sponsor of the platform. The development of the platform will be an iterative process, currently separated into two phases. Utilities will be expected to transmit data to the platform through processes to be established with the Program Manager (to be determined). The Order established a combined cost cap of $12 Million for NYSEG and RG&E for Phase 1, to be deferred and recovered in the next rate case filing after Phase 1 is complete. On April 15, 2021, the Commission issued an Order Adopting a Data Access Framework and Establishing Further Process ("DAF Order"). The DAF Order establishes a centralized data access certification process. On May 14, 2021, a stakeholder (Mission:data Coalition) filed a petition for rehearing on the DAF Order citing concerns with the audit requirements. The NY utilities also jointly filed a petition for rehearing on May 17, 2021 regarding the Commission's directive to remove fees for certain requests for data. The Commission issued an Order on November 18, 2021 denying both requests for rehearing.

On December 13, 2018, the Commission issued an Order for NYSEG to file an implementation plan detailing a competitive procurement process and cost recovery for deploying 10 MW of qualified storage systems. NYSEG filed its implementation plan and has issued requests for proposals to site storage systems within their service territory. On April 16, 2021, the Commission issued an Order to modify the term offered to developers for energy storage contracts and extended the in-service date for deployment of the 10 MW of energy storage. The Companies have tariffs in effect to collect costs for the procurement of qualified energy storage assets.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2018 Winter Storms

In March 2018, following two severe winter storms that impacted more than one million electric utility customers in New York, including 520,000 NYSEG and RG&E customers, the New York Department of Public Service ("NYDPS") initiated a comprehensive investigation of all the New York electric utilities' preparation and response to those events. The investigation was expanded to include other 2018 New York spring storm events.

On April 18, 2019, the NYDPS staff issued a report (the 2018 Staff Report) of the findings from their investigation. The 2018 Staff Report identifies 94 recommendations for corrective actions to be implemented in the utilities' Emergency Response Plans (ERPs). The 2018 Staff Report also identified potential violations by several of the utilities, including NYSEG and RG&E.

Also on April 18, 2019, the NYPSC issued an Order Instituting Proceeding and to Show Cause directed to all major electric utilities in New York, including NYSEG and RG&E. The order directed the utilities, including NYSEG and RG&E, to show cause why the NYPSC should not pursue civil penalties, and/or administrative penalties for the apparent failure to follow their respective ERPs as approved and mandated by the NYPSC. The NYPSC also directed the utilities, within 30 days, to address whether the NYPSC should mandate, reject or modify in whole or in part, the 94 recommendations contained in the 2018 Staff Report. On May 20, 2019, NYSEG and RG&E responded to the portion of the Order to Show Cause with respect to the recommendations contained in the 2018 Staff Report. The Commission granted the companies a series of extensions to respond to the portion of the Order to Show Cause with respect to why the Commission should not pursue a penalty action. A joint settlement agreement to avoid litigation including NYSEG and RG&E's agreement to pay a penalty of $10.5 million (allocated as $9.0 million to NYSEG and $1.5 million to RG&E) was filed with the NYPSC on December 17, 2019. On February 6, 2020, the NYPSC approved the joint settlement agreement, and the penalty amount is reflected as a rate moderator in the recently approved Joint Proposal.

NYPSC Directs Counsel to Commence Judicial Enforcement Proceeding Against NYSEG

On April 18, 2019, the NYPSC issued an Order Directing Counsel to the Commission to commence a special proceeding or an action in New York State Supreme Court to stop and prevent ongoing future violations by NYSEG of NYPSC regulations and orders. On December 24, 2019, the NYPSC filed a Verified Petition to commence the action against NYSEG and NYSEG and the NYPSC settled the causes of action asserted in the Verified Petition and entered into a Consent and Stipulation. On December 24, 2019, NYSEG and the NYPSC submitted a joint motion to the New York State Supreme Court (the "Court") requesting that the court approve and enter a Consent Order and Judgment reflecting the settlement. The Court issued the requested Consent Order and Judgment on January 24, 2020.

NYDPS Investigation of the Preparation for and Response to the Tropical Storm Isaias

On August 5, 2020, the NYDPS commenced an investigation into the preparation for and response to the Tropical Storm Isaias by several utilities in New York including NYSEG. In addition, the New York State Senate and Assembly held a joint hearing to examine the response of various utility companies during the aftermath of Tropical Storm Isaias. In August 2020, the Company received a letter from the NYDPS requesting a series of follow-on actions, which the Company has completed or is in the process of completing. At its November 19, 2020 session, the NYPSC provided an interim status report on the investigation, and NYSEG was identified as having a few items for improvement. The NYDPS subsequently provided NYSEG with a proposed settlement at $500,000 per violation, related to three alleged violations. NYSEG signed an agreement associated with the settlement, and that agreement was accepted by the NYPSC at its January 2021 session.

Minimum Equity Requirements for Regulated Subsidiaries

NYSEG is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, NYSEG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, NYSEG must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. NYSEG is prohibited by regulation from lending to unregulated affiliates. NYSEG has also agreed to minimum equity ratio requirements in certain borrowing agreements. These requirements are lower than the regulatory requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable.

We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $175.5 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

On November 19, 2020, the NYPSC approved the Proposal in connection with a three-year rate plan for electric and gas service at NYSEG effective April 17, 2020. Following the approval of the proposal most of these items related to NYSEG are amortized over a three- or five-year period, except the portion of storm costs to be recovered over ten years, plant related tax items which are amortized over the life of associated plant, and unfunded deferred taxes which are amortized over forty six years. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, annual net amortization revenue for NYSEG is approximately $80.2 million for the year ended December 31, 2021.

Current and non-current regulatory assets at December 31, 2021 and 2020 consisted of:

December 31,	2021	2020
(Thousands)		
Current		
Electric supply reconciliation	$ 8,213	$ 1,201
Federal tax depreciation normalization adjustment	3,788	3,788
Hedge losses	—	10,620
Low income programs	945	945
Pension and other post-retirement benefits cost deferrals	14,688	14,688
Rate adjustment mechanism	21,680	20,695
Rate change levelization	11,354	—
Revenue decoupling mechanism	2,661	8,712
Storm costs	25,992	25,992
Unamortized loss on re-acquired debt	1,718	1,718
Value distributed energy resource	11,849	—
Other	9,534	9,737
Total current regulatory assets	**112,422**	**98,096**
Non-current		
Asset retirement obligation	11,757	12,428
Environmental remediation costs	68,251	86,764
Federal tax depreciation normalization adjustment	79,424	83,224
Low income programs	7,926	3,593
Merger capital expenditure	21	291
Pension and other post-retirement benefits	114,164	278,118
Pension and other post-retirement benefits cost deferrals	45,328	57,676
Rate adjustment mechanism	32,397	10,749
Storm costs	272,994	265,227
Unamortized loss on re-acquired debt	11,411	13,129
Vegetation management	27,370	—
Other	71,117	56,360
Total non-current regulatory assets	**$ 742,160**	**$ 867,559**

Asset retirement obligations represent the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

Electric supply reconciliation represents over/under collection of costs related to electric supply in which NYSEG supplies electricity as the default service option for customers.

Environmental remediation costs include spending that has occurred and is eligible for future return/recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

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Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with deferred income tax.

Hedge losses regulatory asset represents the deferred fair value losses on electric and gas hedge contracts.

Low income programs represent deferrals related to over/under spending on Low-Income customer assistance programs.

Merger capital expense target customer credit account was created as a result of NYSEG not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is three years following the approval of the proposal by the NYPSC.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. A portion of this balance is amortized through current rates over a five-year amortization period which began in 2020. The remaining balance will be refunded in future periods through future rate cases.

Rate adjustment Mechanism (RAM) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but it also includes property taxes,REV costs and fees not covered in other recovery mechanisms, energy efficiency program costs, and COVID customer bill credits.

Rate change levelization represents NY delivery rate levelization to smooth the rate increase across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Storm costs for NYSEG are allowed in rates based on an estimate of the routine costs of service restoration. NYSEG is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. Since the approval of the 2010 rate plan in New York (see Note 2), we have experienced unusually high levels of restoration costs resulting from various storms including Hurricane Sandy, Hurricane Irene and tropical storm Lee. NYSEG's total storm balance was $299.0 million at December 31, 2021 and $291.2 million at December 31, 2020. Pursuant to the most recent Joint Proposal approved by the Commission, which began May 1, 2020, NYSEG will recover $33.0 million of the balance over five years and $119.2 million of the balance over ten years for non-super-storms, and $74.8 million of the balance over ten years for the super-storm balance.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Value distributed energy resource represent a mechanism to compensate energy created by distributed energy resources like solar.

Vegetation management represents a program to address danger trees outside of the distribution right-of-way, including but not limited to, ash trees.

Other includes items such as COVID customer bill credits not in RAM and Reforming the Energy Vision (REV).

Current and non-current regulatory liabilities at December 31, 2021 and 2020 consisted of:

December 31,	2021	2020
(Thousands)		
Current		
Carrying costs on deferred income tax depreciation	$ 3,338	$ 3,338
Carrying costs on mixed use 263(a)	2,666	2,666
Debt rate reconciliation	8,741	8,741
Economic development	1,052	1,052
Energy efficiency programs	12,764	8,241
Gas supply charge and deferred natural gas cost	5,003	876
Hedge gains	7,921	—
Merchant function charge	1,406	—
New York 2018 winter storm settlement	3,000	3,000
Non by-passable charges	5,695	7,629
Pension and other postretirement benefits cost deferral	4,621	4,621
Positive benefit adjustment	969	969
Property tax	1,401	1,401
Rate change levelization	—	1,318
Service quality performance mechanism	2,922	2,922
Tax Act-remeasurement	34,114	48,034
Theoretical reserve flow through impact	2,097	2,097
Other	8,730	10,660
Total current regulatory liabilities	**106,440**	**107,565**
Non-current		
Accrued removal obligation	496,392	518,571
Accumulated deferred investment tax credits	11,841	12,102
Carrying costs on deferred income tax depreciation	—	3,333
Debt rate reconciliation	23,332	30,347
Economic development	6,524	6,288
New York 2018 winter storm settlement	2,782	5,688
Pension and other postretirement benefits	19,125	8,615
Pension and other postretirement benefits cost deferral	13,280	17,890
Positive benefit adjustment	79	1,061
Rate change levelization	40,857	—
Service quality performance mechanism	17,341	12,658
Tax Act-remeasurement	376,658	410,145
Unfunded future income taxes	80	9,562
Other	66,595	108,523
Total non-current regulatory liabilities	**$ 1,074,886**	**$ 1,144,783**

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Accumulated deferred investment tax credits represent investment tax credits related to plant investments that are deferred when earned and amortized over the estimated lives of the related assets.

Carrying costs on deferred income tax bonus depreciation represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. The amortization period is five years following the approval of the proposal by the NYPSC.

Carrying costs on mixed services 263(a) represent the carrying costs benefit of increased accumulated deferred income taxes created by Section 263(a) IRC. The amortization period in current rates is three years and began in 2020.

Debt rate reconciliation represents the over/under collection of costs related to fixed and variable rate debt instruments identified in the rate case. Costs include interest, commissions and fees versus amounts included in rates.

Economic development represents the economic development program which enables NYSEG to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to NYSEG varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

Energy efficiency portfolio standard represents the costs of energy efficiency programs deferred for future recovery to the extent they exceed the amount in rates. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

Gas supply costs represent the actual costs of purchasing, transporting and storing natural gas for those customers who receive their natural gas supply from NYSEG.

Hedge gains regulatory liability represents the deferred fair value gains on electric and gas hedge contracts.

Merchant function charge represents the administrative costs of obtaining natural gas supply. Customers with supplier other than NYSEG are not charged for this service.

New York 2018 winter storm settlement represents the settlement amount with the NYSPSC following the comprehensive investigation of New York's major utility companies' preparation and response to March 2018 storms. This balance is amortized through current rates over an amortization period of three years, beginning in 2020.

Non by-passable charges represent the non by-passable charge paid by all customers. An asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered. This liability will be refunded to customers within the next year.

Pension and other postretirement benefits represent the actuarial gains on pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future expenses. Because no funds have yet been received for this, a regulatory liability is not reflected within rate base. They also represent the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of Energy East. This is being used to moderate increases in rates. The amortization period is three years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.

Deferred property taxes represent the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The New York (NY) amount is being amortized over a five year period following the approval of the proposal by the NYPSC.
Rate change levelization represents NY delivery rate levelization to smooth the rate increase across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates. The amortization period in current rates is five years and began in 2020.

Service quality performance mechanism represents negative revenue adjustments as well positive rate adjustments for exceeding and/or failing to meet targets for certain performance measures including the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI), certain gas safety performance measures and for uncollectible/terminations/arrears measures.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The amortization period in current rates is from one and half to ten years and began in 2020.

Theoretical reserve flow through impact represents the differences from the rate allowance for applicable federal and state flow through impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. The amortization period is five years following the approval of the proposal by the NYPSC.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes various items subject to reconciliation including low income, earnings sharing provision and asset retirement obligations.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

NYSEG derives its revenue primarily from tariff-based sales of electricity and natural gas service to customers in New York with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity and natural gas.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. In New York, customers have the option to obtain the electricity or natural gas commodity directly from the utility or from another supplier. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity or natural gas provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the New York Independent System Operator (NYISO) or PJM Interconnection, LLC (PJM), as applicable. Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as NYSEG delivers or sells the electricity or natural gas or provides the transmission service.

NYSEG records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. The NYSEG ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

NYSEG also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period, and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years. TCC contract liabilities totaled $15.4 million at December 31, 2021, and $8.2 million at

December 31, 2020, and are presented in "Other current liabilities" on our balance sheets. We recognized $20.6 million and $19.7 million as revenue during the years ended December 31, 2021 and 2020, respectively.

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for the years ended December 31, 2021 and 2020 are as follows:

Years Ended December 31,	**2021**	**2020**
(Thousands)		
Regulated operations – electricity	$ 1,428,894	$ 1,240,267
Regulated operations – natural gas	322,073	282,569
Other(a)	25,861	19,953
Revenue from contracts with customers	**1,776,828**	**1,542,789**
Leasing revenue	1,166	1,132
Alternative revenue programs	15,489	14,985
Other revenue	10,970	5,335
Total operating revenues	**$ 1,804,453**	**$ 1,564,241**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	**2021**	**2020**
(Thousands)		
Current		
Federal	$ (61)	$ (5,538)
State	(10,979)	(5,649)
Current taxes charged to benefit	**(11,040)**	**(11,187)**
Deferred		
Federal	(2,344)	3,290
State	23,327	11,642
Deferred taxes charged to expense (benefit)	**20,983**	**14,932**
Investment tax credit adjustments	(638)	(383)
Total Income Tax Expense	**$ 9,305**	**$ 3,362**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2021 and 2020, respectively, consisted of:

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Years Ended December 31,		2021		2020
(Thousands)				
Tax expense at statutory rate	$	34,323	$	27,995
Equity AFUDC tax effects		(4,764)		(3,095)
Excess ADIT giveback		(29,444)		(25,247)
Investment tax credit amortization		(638)		(383)
State tax expense, net of federal benefit		9,755		4,734
Other, net		73		(642)
Total Income Tax Expense	**$**	**9,305**	**$**	**3,362**

Income tax expense for the year ended December 31, 2021 was $25.0 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess ADIT amortization and AFUDC Equity tax effects, partially offset by state taxes. This resulted in an effective tax rate of 5.7%. Income tax expense for the year ended December 31, 2020 was $24.6 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess ADIT amortization and AFUDC Equity tax effects, partially offset by state taxes. This resulted in an effective tax rate of 2.5%.

In 2020, NYSEG began refunding previously deferred protected and unprotected Excess ADIT, established as a result of the 2017 Tax Act as part of the 2020 Joint Proposal and as determined by the NYPSC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2021 and 2020 consisted of:

December 31,		2021		2020
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	753,028	$	692,624
Storm costs		88,688		82,290
Pension and other post-retirement benefits		809		17,645
Power tax deferred income tax		21,823		22,767
Regulatory liability due to "Tax Cuts and Jobs Act"		(107,727)		(119,883)
Environmental		(24,256)		(28,875)
Federal and state NOL’s		(61,242)		(48,557)
Other		(7,028)		(22,635)
Total Non-current Deferred Income Tax Liabilities	**$**	**664,095**	**$**	**595,376**
Deferred tax assets	$	200,253	$	219,950
Deferred tax liabilities		864,348		815,326
Net Accumulated Deferred Income Tax Liabilities	**$**	**664,095**	**$**	**595,376**

NYSEG has gross federal net operating losses of $209.1 million and gross NY state net operating losses of $331.5 million for the year ended December 31, 2021. NYSEG had gross federal net operating losses of $141.9 million and gross NY state net operating losses of $346 million for the year ended December 31, 2020.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Balance as of January 1	$ 45,124	$ 45,197
Reduction for tax positions related to prior years	(73)	(73)
Balance as of December 31	**$ 45,051**	**$ 45,124**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2021 and 2020.

Note 6. Long-term Debt

Long-term debt as of December 31, 2021 and 2020 consisted of:

As of December 31,		2021		2020	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured debt	2022-2049	$ 1,700,000	1.95% - 5.75%	$ 1,350,000	1.95% - 5.75%
Unsecured pollution control notes – fixed	2023-2029	386,000	1.40% - 3.50%	386,000	1.40% - 3.50%
Unamortized debt issuance costs and discount		(15,606)		(11,761)	
Total Debt		**$2,070,394**		**$1,724,239**	
Less: debt due within one year, included in current liabilities		73,083		—	
Total Non-current Debt		**$ 1,997,311**		**$ 1,724,239**	

On May 1, 2020, NYSEG remarketed $200 million of Pollution Control Notes maturing during 2026 through 2029 at an interest ranging from 1.40% to 1.61%.

On September 25, 2020, NYSEG issued $200 million aggregate principal amount of unsecured notes maturing in 2030 at an interest of 1.95%.

On September 24, 2021, NYSEG issued $350 million aggregate principal amount of unsecured notes maturing in 2031 at an interest of 2.15%.

Long-term debt, including sinking fund obligations, due over the next five years consist of:

2022	2023	2024	2025	2026	Total
(Thousands)					
$73,083	$300,000	$12,000	$—	$565,000	$950,083

Note 7. Bank Loans and Other Borrowings

NYSEG had $79.8 million notes payable at December 31, 2021 and no notes payable at December 31, 2020, respectively. NYSEG funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which NYSEG is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. NYSEG has a lending/borrowing limit of $100 million under this agreement. NYSEG had $64.6 million outstanding under this agreement at December 31, 2021 and no debt outstanding under this agreement at December 31, 2020, respectively.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. NYSEG had $15.2 million outstanding under this agreement at December 31, 2021 and no debt outstanding under this agreement at December 31, 2020, respectively.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (NYSEG, Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. NYSEG had no outstanding balance as of December 31, 2021 and December 31, 2020.

In the AGR Credit Facility we covenant not to permit, without the consent of the lenders, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants beyond any applicable cure period, constitutes an event of default, and events of default could result in termination or reduction of lenders' commitments or acceleration of amounts owed under the facility. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.52 to 1.00 at December 31, 2021. We are not in default as of December 31, 2021.

Note 8. Preferred Stock Redeemable Solely at the Option of the Company

At December 31, 2021, NYSEG had 2,455,000 shares of $100 par value preferred stock, 10,800,000 shares of $25 par value preferred stock and 1,000,000 shares of $100 par value preference stock authorized but unissued.

Note 9. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 to 50 years, some of which may include options to extend the leases for up to 20 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

Years Ended December 31,	**2021**	**2020**
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 2,923	$ 4,884
Interest on lease liabilities	143	188
Total finance lease cost	3,066	5,072
Operating lease cost	1,384	1,865
Short-term lease cost	756	581
Variable lease cost	295	385
Intercompany	(61)	(93)
Total lease cost	**$ 5,440**	**$ 7,810**

Balance sheet and other information for the years ended December 31, 2021 and 2020 was as follows:

Notes to Financial Statements

As of December 31,		2021		2020
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right of use assets	$	8,345	$	8,896
Operating lease liabilities, current		915		1,015
Operating lease liabilities, long-term		8,294		8,659
Total operating lease liabilities	$	9,209	$	9,674
Finance Leases				
Other assets	$	32,056	$	34,964
Other current liabilities		200		321
Other non-current liabilities		2,008		2,235
Total finance lease liabilities	$	2,208	$	2,556
Weighted-average Remaining Lease Term (years):				
Finance leases		9.16		9.71
Operating leases		9.85		10.53
Weighted-average Discount Rate:				
Finance leases		5.72 %		5.60 %
Operating leases		3.33 %		3.33 %

Supplemental cash flows information related to leases was as follows:

Years Ended December 31,		2021		2020
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	1,184	$	1,615
Operating cash flows from finance leases	$	143	$	188
Financing cash flows from finance leases	$	381	$	1,826
Right-of-use assets obtained in exchange for lease obligations:				
Finance leases	$	15	$	228
Operating leases	$	542	$	990

Maturities of lease liabilities were as follows:

(Thousands)	Finance	Operating
Years Ended December 31,		
2022	$ 323	$ 1,147
2023	320	1,322
2024	320	1,036
2025	320	1,169
2026	401	971
Thereafter	1,211	5,375
Total lease payments	**2,895**	**11,020**
Less: imputed interest	(687)	(1,811)
Total	**$ 2,208**	**$ 9,209**

Most of our leases do not provide an implicit rate in the lease, thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 10. Commitments and Contingencies

Purchase power and natural gas contracts, including nonutility generators

NYSEG is the provider of last resort for customers. As a result, the company buys physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, NYSEG is required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The company enters into financial swaps to comply with the hedge requirement for physical electric energy purchases. NYSEG also makes purchases from other independent power producers and New York Power Authority (NYPA) under existing contracts or long-term supply agreements in order to comply with the company’s Public Utility Regulatory Policies Act (PURPA) purchase obligation.

NYSEG satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by the company are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The company purchases the majority of its natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The company acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The company acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately $81.1 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2021 and $66.8 million in 2020.

Note 11. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

Waste sites

The Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at twelve waste sites. The twelve sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the twelve sites, ten sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and three sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites.

We have a liability recorded of $5.0 million as of December 31, 2021, related to the twelve sites. We have paid remediation costs related to the twelve sites. We have recorded an estimated liability of $0.5 million related to other two sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. It is possible that the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $5.5 million to $6.1 million as of December 31, 2021. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. Any cost will be flowed through to NYSEG ratepayers.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our 39 sites where gas was manufactured in the past. In 1994 and 1996 we entered into orders on consent with the NYSDEC. Those orders require us to investigate and, where necessary, remediate 38 of our 39 sites. Eight sites are included in the New York State Registry.

Our estimate for all costs related to investigation and remediation of the 39 sites ranges from $79.2 million to $159.1 million at December 31, 2021. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $87.0 million at December 31, 2021 and $104.9 million at December 31, 2020. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy described below, because we expect to recover the net costs in rates.

Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2053.

FirstEnergy

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at sixteen former manufactured gas sites, which are included in the discussion above. In July 2011, the District Court issued a decision and order in NYSEG's favor. Based on past and future clean-up costs at the sixteen sites in dispute, FirstEnergy would be required to pay NYSEG approximately $60 million if the decision were upheld on appeal. On September 9, 2011, FirstEnergy paid NYSEG $30 million, representing their share of past costs of $27 million and pre-judgment interest of $3 million.

FirstEnergy appealed the decision to the Second Circuit Court of Appeals. On September 11, 2014, the Second Circuit Court of Appeals affirmed the District Court's decision in NYSEG's favor, but modified the decision for nine sites, reducing NYSEG's damages for incurred costs from $27 million to $22 million, excluding interest, and reducing FirstEnergy's allocable share of future costs at these sites. NYSEG refunded FirstEnergy the excess $5 million in November 2014.

FirstEnergy remains liable for a substantial share of clean up expenses at nine manufactured gas plant (MGP) sites. Based on current projections, FirstEnergy's share is estimated at approximately $14.2 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Note 12. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of December 31, 2021 and 2020, respectively, and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2021 and 2020, respectively, are as follows:

	Loss or Gain Recognized in Regulatory Assets/ Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	Loss (Gain) Reclassified From Regulatory Assets/ Liabilities Into Income	
(Thousands)					
As of			Years Ended December 31,		
December 31, 2021	Electricity	Natural Gas	2021	Electricity	Natural Gas
Regulatory assets	$ —	$ 48	Purchased power, natural gas and fuel used	$ (14,291)	$ (4,625)
Regulatory liabilities	$ (8,347)	$ (684)			
December 31, 2020			2020		
Regulatory assets	$ 10,519	$ 152	Purchased power, natural gas and fuel used	$ 34,926	$ 859
Regulatory liabilities	$ (44)	$ —			

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	Mwhs	Dths	Gallons
As of December 31, 2021			
2022	2,838,275	2,410,000	1,120,300
2023	998,625	250,000	—
As of December 31, 2020			
2021	2,539,725	2,690,000	1,435,000
2022	876,000	320,000	—

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2021 and 2020, respectively, consisted of:

December 31, 2021	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 17,432	$ 4,245	$ 9,511	$ 3,136
Derivative liabilities	(9,511)	(3,135)	(9,511)	(3,184)
	7,921	1,110	—	(48)
Designated as hedging instruments				
Derivative assets	111	—	55	—
Derivative liabilities	(55)	—	(82)	—
	56	—	(27)	—
Total derivatives before offset of cash collateral	7,977	1,110	(27)	(48)
Cash collateral receivable	—	—	—	48
Total derivatives as presented in the balance sheet	**$ 7,977**	**$ 1,110**	**$ (27)**	**$ —**

December 31, 2020	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 1,692	$ 1,817	$ 1,692	$ 1,773
Derivative liabilities	(1,692)	(1,773)	(12,312)	(1,824)
	—	44	(10,620)	(51)
Designated as hedging instruments				
Derivative assets	5	—	5	—
Derivative liabilities	(5)	—	(275)	—
	—	—	(270)	—
Total derivatives before offset of cash collateral	—	44	(10,890)	(51)
Cash collateral receivable	—	—	10,620	51
Total derivatives as presented in the balance sheet	**$ —**	**$ 44**	**$ (270)**	**$ —**

As of December 31, 2021 and 2020, the derivative assets – non-current are presented within other non-current assets of the balance sheet. The derivative liabilities – non-current are presented within other non-current liabilities of the balance sheet.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging instruments on OCI and income for the years ended December 31, 2021 and 2020, respectively, consisted of:

Years Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of (Loss) Gain Reclassified From Accumulated OCI into Income	(Loss) Gain Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2021				
Interest rate contracts	$ —	Interest expense	$ (105)	$ 54,373
Commodity contracts: Other	827	Operations and maintenance	501	756,212
Foreign exchange contracts	(27)	Operations and maintenance	—	756,212
Total	**$ 800**		**$ 396**	
2020				
Interest rate contracts	$ —	Interest expense	$ (105)	$ 65,777
Commodity contracts: Other	(682)	Other operating expenses	(634)	705,205
Total	**$ (682)**		**$ (739)**	

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2021, is a net loss of $0.1 million as compared to a net loss of $0.3 million for 2020. For the year ended December 31, 2021, we recorded $0.1 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $0.1 million of discontinued cash flow hedges in 2022.

As of December 31, 2021, $0.1 million in gains are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of hedge recognized during the year ended December 31, 2021.

We face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or Standard & Poor's). When our exposure to risk for counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2021 is $0.1 million for which we have posted collateral.

Note 13. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $2,159 million and $1,918 million as of December 31, 2021 and 2020, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2021 and 2020, consisted of:

Description		(Level 1)		(Level 2)		(Level 3)		Netting		Total
(Thousands)										
As of December 31, 2021										
Assets										
Non-current investments available for sale, primarily money market funds	$	10,561	$	—	$	—	$	—	$	10,561
Derivatives										
Commodity contracts:										
Electricity		20,798		—		—		(12,451)		8,347
Natural gas		879		—		—		(195)		684
Other		—		—		111		(55)		56
Total	**$**	**32,238**	**$**	**—**	**$**	**111**	**$**	**(12,701)**	**$**	**19,648**
Liabilities										
Derivatives										
Commodity contracts:										
Electricity	$	(12,451)	$	—	$	—	$	12,451	$	—
Natural gas		(244)		—		—		244		—
Other		—		—		(55)		55		—
Foreign exchange contracts		—		(27)		—		—		(27)
Total	**$**	**(12,695)**	**$**	**(27)**	**$**	**(55)**	**$**	**12,750**	**$**	**(27)**
As of December 31, 2020										
Assets										
Non-current investments available for sale, primarily money market funds	$	10,447	$	—	$	—	$	—	$	10,447
Derivatives										
Commodity contracts:										
Electricity		3,413		—		—		(3,369)		44
Natural gas		96		—		—		(96)		—
Other		—		—		5		(5)		—
Total	**$**	**13,956**	**$**	**—**	**$**	**5**	**$**	**(3,470)**	**$**	**10,491**
Liabilities										
Derivatives										
Commodity contracts:										
Electricity	$	(13,888)	$	—	$	—	$	13,888	$	—
Natural gas		(248)		—		—		248		—
Other		—		—		(275)		5		(270)
Total	**$**	**(14,136)**	**$**	**—**	**$**	**(275)**	**$**	**14,141**	**$**	**(270)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2021 and 2020. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

We determine the fair value of our derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2021 and 2020 consisted of:

	(Level 3) Derivatives, Net	
Years Ended December 31,	**2021**	**2020**
(Thousands)		
Beginning balance	$ (270)	$ (222)
Realized (gains) losses included in earnings	(501)	634
Unrealized gains (losses) included in other comprehensive income	827	(682)
Ending balance	**$ 56**	**$ (270)**

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 14. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2021 and 2020, consisted of:

(Thousands)	Balance, December 31, 2019	Change 2020	Balance, December 31, 2020	Change 2021	Balance, December 31, 2021
Amortization of pension cost for non-qualified plans, net of income tax expense of $10 for 2020 and $38 for 2021	$ (538)	$ (459)	$ (997)	$ 108	$ (889)
Unrealized gain (loss) on derivatives qualified as hedges:					
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax (benefit) expense of ($590) for 2020 and $314 for 2021		(92)		486	
Reclassification adjustment for (gain) loss included in net income, net of income tax expense (benefit) of $549 for 2020 and ($197) for 2021		85		(304)	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $91 for 2020 and $42 for 2021		14		63	
Net unrealized gain (loss) on derivatives qualified as hedges	(532)	7	(525)	245	(280)
Accumulated Other Comprehensive Loss	**$ (1,070)**	**$ (452)**	**$ (1,522)**	**$ 353**	**$ (1,169)**

Note 15. Post-retirement and Similar Obligations

We have funded non-contributory defined benefit pension plans that cover all eligible employees. For employees hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, we announced that we would stop the cash balance accruals for all non-union employees covered under the cash balance plans effective December 31, 2013. NYSEG's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2015. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for those employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $11.3 million for 2021 and $8.3 million for 2020.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $3.3 million and $3.8 million at December 31, 2021 and 2020, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 1,730,911	$ 1,649,246	$ 161,600	$ 160,382
Service cost	16,270	19,378	1,047	1,084
Interest cost	38,597	47,012	3,354	4,523
Actuarial (gain)/loss	(77,307)	112,401	(9,829)	7,899
Benefits paid	(115,641)	(97,126)	(13,037)	(12,288)
Benefit obligation at December 31	**$ 1,592,830**	**$ 1,730,911**	**$ 143,135**	**$ 161,600**
Change in plan assets				
Fair value of plan assets at January 1	$ 1,550,984	$ 1,450,765	$ 80,309	$ 76,911
Actual return on plan assets	107,718	197,345	4,989	9,030
Employer & plan participants' contributions	—	—	—	6,656
Benefits paid	(115,641)	(97,126)	(35,956)	(12,288)
Fair value of plan assets at December 31	**$ 1,543,061**	**$ 1,550,984**	**$ 49,342**	**$ 80,309**
Funded status	**$ (49,769)**	**$ (179,927)**	**$ (93,793)**	**$ (81,291)**

During 2021, the pension benefit obligation had an actuarial gain of $77.3 million. This gain was primarily driven by $103.3 million gain from increase in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2020, the pension benefit obligation had an actuarial loss of $112.4 million. This loss was primarily driven by $121.5 million loss from decrease in discount rates. There were no significant plan design changes in 2020. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Noncurrent liabilities	$ (49,769)	$ (179,927)	$ (93,793)	$ (81,291)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities consist of:

As of December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net loss (gain)	$ 112,045	$ 275,337	$ (19,125)	$ (5,937)
Prior service cost (credit)	$ 2,119	$ 2,781	$ —	$ (2,678)

Our accumulated benefit obligation for all qualified defined benefit pension plans was $1,535 million and $1,664 million as of December 31, 2021 and 2020. NYSEG's postretirement benefits were partially funded as of December 31, 2021 and 2020.

The projected benefit obligation exceeded the fair value of pension plan assets for our qualified plans as of both December 31, 2021 and 2020. The accumulated benefit obligation did not exceed the fair value of pension plan assets as of December 31, 2021. The accumulated benefit obligation exceeded the fair value of pension plan assets as of December 31, 2020. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2021 and 2020.

As of December 31,	2021	2020
(Thousands)		
Projected benefit obligation	$ 1,592,830	$ 1,730,911
Accumulated benefit obligation	$ 1,535,479	$ 1,663,645
Fair value of plan assets	$ 1,543,061	$ 1,550,984

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2021 and 2020.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net periodic benefit cost				
Service cost	$ 16,270	$ 19,378	$ 1,047	$ 1,084
Interest cost	38,597	47,012	3,354	4,523
Expected return on plan assets	(97,894)	(99,997)	(2,409)	(3,230)
Amortization of prior service cost (credit)	662	791	(2,678)	(5,495)
Amortization of net loss	76,161	83,880	779	1,252
Net periodic benefit cost	**$ 33,796**	**$ 51,064**	**$ 93**	**$ (1,866)**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ (87,131)	$ 15,054	$ (12,409)	$ 2,100
Amortization of net loss	(76,161)	(83,880)	(779)	(1,252)
Amortization of prior service (cost) credit	(662)	(791)	2,678	5,495
Total recognized in regulatory assets and regulatory liabilities	**$ (163,954)**	**$ (69,617)**	**$ (10,510)**	**$ 6,343**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (130,158)**	**$ (18,553)**	**$ (10,417)**	**$ 4,477**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate	2.85 %	2.29 %	2.61 %	2.15 %
Rate of compensation increase	Age-Related Rates / 3.00% Union	Age-Related Rates	3.00% Union	3.00 %
Interest crediting rate	3.00 %	3.00 %	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate developing a yield curve derived from a portfolio of high grade non-callable bonds with yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate	2.29 %	2.93 %	2.15 %	2.93 %
Expected long-term return on plan assets	7.00 %	7.30 %	3.00 %	— %
Expected long-term return on plan assets - nontaxable trust	— %	— %	— %	6.40 %
Expected long-term return on plan assets - taxable trust	— %	— %	— %	4.20 %
Rate of compensation increase	Age-Related Rates / 3.00% Union	Age-Related Rates	3.00% Union	Age-Related Rates

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	2021	2020
Health care cost trend rate (pre 65/post 65)	6.50% / 7.25%	6.75% / 7.50%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029 / 2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension and postretirement benefit plans in 2022.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2022	$ 92,458	$ 10,644	$ —
2023	$ 93,901	$ 10,534	$ —
2024	$ 95,910	$ 10,328	$ —
2025	$ 97,488	$ 10,100	$ —
2026	$ 98,759	$ 9,836	$ —
2027-2031	$ 486,088	$ 43,545	$ —

***Plan assets*:** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets as of December 31, 2021, by asset category, consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 33,572	$ 12,405	$ 21,167	$ —
U.S. government securities	209,504	209,504	—	—
Common stocks	69,435	69,435	—	—
Registered investment companies	132,377	132,377	—	—
Corporate bonds	435,532	—	435,532	—
Preferred stocks	533	533	—	—
Common collective trusts	314,001	—	314,001	—
Other, principally annuity, fixed income	35,481	4	35,477	—
	$ 1,230,435	**$ 424,258**	**$ 806,177**	**$ —**
Other investments measured at net asset value	312,626			
Total	**$ 1,543,061**			

The fair values of pension benefits plan assets as of December 31, 2020, by asset category, consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2020				
Cash and cash equivalents	$ 68,721	$ 52	$ 68,669	$ —
U.S. government securities	88,789	88,762	27	—
Common stocks	54,237	54,237	—	—
Registered investment companies	150,711	150,711	—	—
Corporate bonds	356,162	—	356,162	—
Preferred stocks	493	493	—	—
Common collective trusts	485,686	—	485,686	—
Other, principally annuity, fixed income	34,238	3,182	31,056	—
	$ 1,239,037	**$ 297,437**	**$ 941,600**	**$ —**
Other investments measured at net asset value	311,947			
Total	**$ 1,550,984**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stock - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. NYSEG's postretirement benefits plan assets are invested in a VEBA arrangement that is subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49% - 69% for equity securities and 31%- 51% for fixed income investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2021 consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 2,097	$ —	$ 2,097	$ —
Registered investment companies	47,245	47,245	—	—
Total	**$ 49,342**	**$ 47,245**	**$ 2,097**	**$ —**

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2020 consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2020				
Cash and cash equivalents	$ 2,624	$ —	$ 2,624	$ —
U.S. government securities	235	235	—	—
Common stocks	144	144	—	—
Registered investment companies	74,246	74,246	—	—
Corporate bonds	944	—	944	—
Preferred stocks	1	1	—	—
Common collective trusts	1,281	—	1,281	—
Other, principally annuity, fixed income	5	8	(3)	—
	$ 79,480	**$ 74,634**	**$ 4,846**	**$ —**
Other investments measured at net asset value	829			
Total	**$ 80,309**			

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common stock - at the closing price reported in the active market in which the individual investment is traded.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2021 and 2020.

Note 16. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2021 and 2020, consisted of:

Years Ended December 31,	**2021**	**2020**
(Thousands)		
Interest and dividend income	$ 266	$ 604
Carrying costs on regulatory assets	9,449	15,806
Allowance for funds used during construction	24,249	15,725
Gain on sale of property	—	1,445
Miscellaneous	71	84
Total other income	**$ 34,035**	**$ 33,664**
Pension non-service components	$ (14,268)	$ (24,496)
Miscellaneous	(1,435)	(1,869)
Total other deductions	**$ (15,703)**	**$ (26,365)**

Note 17. Related Party Transactions

Certain Networks subsidiaries, including NYSEG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For NYSEG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including NYSEG, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to NYSEG by AGR and its affiliates was approximately $114.6 million for 2021 and $102.6 million for 2020. Cost for services includes amounts capitalized in utility plant, which was approximately $17.1 million in 2021 and $13.1 million in 2020. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by NYSEG to AGR and its subsidiaries were approximately $16.8 million for 2021 and $16.3 million for 2020. All charges for services are at cost. All of the charges associated with services provided are recorded as revenues to offset other operating expenses on the financial statements. The balance in accounts payable to affiliates of $100.1 million at December 31, 2021 and $34.0 million at December 31, 2020 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $2.4 million at December 31, 2021 and $4.8 million at December 31, 2020 is from various companies. There were no notes receivable from affiliates at December 31, 2021. The balance in notes receivable from affiliates of $7.2 million at December 31, 2020 is receivable from CMP. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

Networks holds an approximate 20% ownership interest in the regulated New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. In 2016 NYSEG received approximately $67 million from New York TransCo in the form of $43 million for assets constructed and transferred to the New York TransCo, $22 million in contributions in aid of construction and approximately $2 million in advanced lease payments for a 99 year lease of land and attachment rights. We had $0.6 million and no outstanding receivable balance from New York TransCo as of December 31, 2021 and 2020, respectively.

Note 18. Subsequent Events

The company has performed a review of subsequent events through March 22, 2022, which is the date these financial statements were available to be issued.

Rochester Gas and Electric Corporation
Financial Statements
As of and for the Years Ended December 31, 2021 and 2020

Rochester Gas and Electric Corporation

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

Shareholders and The Board of Directors
Rochester Gas and Electric Corporation:

Opinion

We have audited the financial statements of Rochester Gas and Electric Corporation (the Company), which comprise the balance sheets as of December 31, 2021 and 2020, and the related statements of income, comprehensive income, changes in common stock equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

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

Responsibilities of Management for the Financial Statements

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

KPMG LLP

New York, New York
March 22, 2022

Rochester Gas and Electric Corporation
Statements of Income

Years Ended December 31,	2021	2020
(Thousands)		
Operating Revenues	**$ 957,789**	**$ 871,943**
Operating Expenses		
Electricity purchased and fuel used in generation	136,998	105,341
Natural gas purchased	103,875	75,743
Operations and maintenance	312,466	288,655
Depreciation and amortization	106,704	104,044
Taxes other than income taxes, net	144,145	132,624
Total Operating Expenses	**804,188**	**706,407**
Operating Income	**153,601**	**165,536**
Other income	18,521	26,831
Other deductions	(5,907)	(13,052)
Interest expense, net of capitalization	(43,898)	(46,186)
Income Before Tax	**122,317**	**133,129**
Income tax expense	19,433	19,635
Net Income	**$ 102,884**	**$ 113,494**

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Years Ended December 31,	2021	2020
(Thousands)		
Net Income	**$ 102,884**	**$ 113,494**
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for non-qualified plans, net of income tax	479	(1,008)
Unrealized gain (loss) during the period on derivatives qualifying as cash flow hedges, net of income tax	186	(126)
Reclassification to net income of (gain) loss on settled cash flow commodity hedges, net of income tax	(132)	129
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax	2,716	2,903
Other Comprehensive Income, Net of Tax	**3,249**	**1,898**
Comprehensive Income	**$ 106,133**	**$ 115,392**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 3	$ 1
Accounts receivable and unbilled revenues, net	171,416	146,321
Accounts receivable from affiliates	2,893	4,761
Notes receivable from affiliates	—	19,200
Fuel and gas in storage	13,903	6,535
Materials and supplies	16,871	14,202
Broker margin accounts	—	5,072
Income tax receivable	3,646	26,305
Prepaid property taxes	41,747	40,053
Regulatory assets	77,459	49,295
Other current assets	12,895	3,413
Total Current Assets	**340,833**	**315,158**
Utility plant, at original cost	4,762,539	4,481,101
Less accumulated depreciation	(1,202,628)	(1,123,051)
Net Utility Plant in Service	**3,559,911**	**3,358,050**
Construction work in progress	332,901	245,206
Total Utility Plant	**3,892,812**	**3,603,256**
Operating lease right of use assets	1,124	1,774
Regulatory and Other Assets		
Regulatory assets	377,240	413,798
Other	51,506	50,195
Total Regulatory and Other Assets	**428,746**	**463,993**
Total Assets	**$ 4,663,515**	**$ 4,384,181**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of debt	$ —	$ 123,738
Notes payable to affiliates	53,500	—
Accounts payable and accrued liabilities	238,380	218,475
Accounts payable to affiliates	48,383	16,332
Interest accrued	7,902	10,067
Taxes accrued	3,967	1,250
Operating lease liabilities	287	142
Environmental remediation costs	4,030	1,142
Regulatory liabilities	101,801	103,528
Other	52,376	47,518
Total Current Liabilities	**510,626**	**522,192**
Regulatory and Other Liabilities		
Regulatory liabilities	695,703	703,806
Other Non-current Liabilities		
Deferred income taxes	416,223	365,121
Nuclear plant obligations	129,414	129,349
Pension and other postretirement	109,979	154,199
Operating lease liabilities	2,253	2,618
Asset retirement obligations	2,430	2,562
Environmental remediation costs	95,604	95,056
Other	58,891	71,252
Total Regulatory and Other Liabilities	**1,510,497**	**1,523,963**
Non-current debt	1,366,168	1,118,136
Total Liabilities	**3,387,291**	**3,164,291**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2021 and 2020)	194,429	194,429
Additional paid-in capital	855,312	655,111
Retained earnings	378,863	525,979
Accumulated other comprehensive loss	(35,142)	(38,391)
Treasury stock, at cost (4,379,300 shares at December 31, 2021 and 2020)	(117,238)	(117,238)
Total Common Stock Equity	**1,276,224**	**1,219,890**
Total Liabilities and Equity	**$ 4,663,515**	**$ 4,384,181**

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Years Ended December 31,	2021	2020
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 102,884**	**$ 113,494**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	106,704	104,044
Regulatory assets/liabilities amortization	(65,697)	(35,066)
Regulatory assets/liabilities carrying cost	2,833	5,260
Amortization of debt issuance costs	1,125	1,239
Deferred taxes	31,177	16,657
Pension cost	9,619	12,027
Stock-based compensation	231	115
Accretion expenses	135	143
Gain from disposal of property	(228)	(49)
Other non-cash items	(10,104)	(23,314)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(23,227)	1,221
Inventories	(10,037)	1,205
Accounts payable, to affiliates, and accrued liabilities	86,702	4,241
Taxes accrued	25,540	3,640
Other assets/liabilities	18,558	5,438
Regulatory assets/liabilities	(3,060)	4,673
Net Cash Provided by Operating Activities	**273,155**	**214,968**
Cash Flow From Investing Activities:		
Capital expenditures	(435,551)	(364,143)
Contributions in aid of construction	20,243	6,459
Proceeds from sale of property, plant and equipment	1,215	655
Notes receivable from affiliates	19,200	(19,200)
Net Cash Used in Investing Activities	**(394,893)**	**(376,229)**
Cash Flow From Financing Activities:		
Non-current note issuance	246,838	196,320
Repayments of non-current debt	(125,000)	—
Repayments of finance leases	(3,598)	(2,436)
Notes payable to affiliates	53,500	(33,201)
Capital contributions	200,000	50,000
Dividends paid	(250,000)	(50,000)
Net Cash Provided by Financing Activities	**121,740**	**160,683**
Net Increase (Decrease) in Cash and Cash Equivalents	**2**	**(578)**
Cash and Cash Equivalents, Beginning of Period	**1**	**579**
Cash and Cash Equivalents, End of Period	**$ 3**	**$ 1**

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

Rochester Gas and Electric Corporation
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of Shares (*)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total Common Stock Equity
Balance, December 31, 2019	**38,885,813**	**$ 194,429**	**$ 605,022**	**$ 462,501**	**$ (40,289)**	**$ (117,238)**	**$ 1,104,425**
Adoption of accounting standards	—	—	—	(16)	—	—	(16)
Net income	—	—	—	113,494	—	—	113,494
Other comprehensive income, net of tax	—	—	—	—	1,898	—	1,898
Comprehensive income							115,392
Stock-based compensation	—	—	89	—	—	—	89
Common stock dividends	—	—	—	(50,000)	—	—	(50,000)
Capital contributions	—	—	50,000	—	—		50,000
Balance, December 31, 2020	**38,885,813**	**$ 194,429**	**$ 655,111**	**$ 525,979**	**$ (38,391)**	**$ (117,238)**	**$ 1,219,890**
Net income	—	—	—	102,884	—	—	102,884
Other comprehensive income, net of tax	—	—	—	—	3,249	—	3,249
Comprehensive income							106,133
Stock-based compensation	—	—	201	—	—	—	201
Common stock dividends	—	—	—	(250,000)	—	—	(250,000)
Capital contributions	—	—	200,000	—	—	—	200,000
Balance, December 31, 2021	**38,885,813**	**$ 194,429**	**$ 855,312**	**$ 378,863**	**$ (35,142)**	**$ (117,238)**	**$ 1,276,224**

(*) Par value of share amounts is $5

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

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

***Background and nature of operations*:** Rochester Gas and Electric Corporation's (RG&E, the company, we, our, us), conducts regulated electricity transmission, distribution, and generation operations and regulated natural gas transportation and distribution operations in western New York. RG&E generates electricity from hydroelectric stations. RG&E serves approximately 388,700 electricity and 321,700 natural gas customers as of December 31, 2021, in its service territory of approximately 2,700 square miles. The service territory contains a substantial suburban area and a large agricultural area in parts of nine counties including and surrounding the city of Rochester, New York with a population of approximately one million people. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

RG&E is a subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Basis of presentation*:** The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

***Significant Accounting Policies*:** We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our financial statements:

***Revenue recognition*:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

***Regulatory accounting*:** We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

***Utility plant*:** We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rate for depreciation was 2.2% of average depreciable property for 2021 and 2.3% for 2020. We amortize our capitalized software cost, which is included in common plant, using the straight-line method, based on useful lives of 7 to 37 years. Capitalized software costs were approximately $155.3 million as of December 31, 2021 and $136.4 million as of December 31, 2020. Depreciation expense was $101.9 million in 2021 and $99.9 million in 2020. Amortization of capitalized software was $4.8 million in 2021 and $4.1 million in 2020.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	**Estimated useful life range (years)**	**2021**	**2020**
(thousands)			
Electric	2-90	$ 3,161,156	$ 3,036,488
Natural Gas	7-80	1,137,048	1,034,476
Common	3-60	464,335	410,137
Utility plant at original cost		**4,762,539**	**4,481,101**
Less accumulated depreciation		(1,202,628)	(1,123,051)
Net Utility Plant in Service		**3,559,911**	**3,358,050**
Construction work in progress		332,901	245,206
Total Utility Plant		**$ 3,892,812**	**$ 3,603,256**

***Leases*:** We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

***Impairment of long-lived assets*:** We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

***Fair value measurement*:** 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

***Derivatives and hedge accounting*:** Derivatives are recognized on our balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs, which we present in the same income statement line item as the earnings effect of the hedged item. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. We record changes in the fair value of electric and natural gas hedge contracts to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

***Cash and cash equivalents*:** Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our balance sheets. We report changes in book overdrafts in the operating activities section of our statements of cash flows.

***Statements of cash flows*:** Supplemental disclosure of cash flow information is as follows:

	2021	2020
(Thousands)		
Cash paid during the years ended December 31:		
Interest, net of amounts capitalized	$ 41,661	$ 31,998
Income taxes (refunded), net	$ (32,460)	$ (304)

Of the income taxes refunded, substantially all was refunded to AGR under the tax sharing agreement. Interest capitalized was $9.2 million in 2021 and $15.7 million in 2020. Accrued liabilities for utility plant additions were $7.0 million in 2021 and $34.7 million in 2020.

***Broker margin accounts*:** We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. We show the amount reflecting those activities as broker margin accounts on our balance sheets.

***Trade receivables and unbilled revenue, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $60.6 million for 2021 and $51.8 million for 2020, and are shown net of an allowance for credit losses at December 31 of $46.7 million for 2021 and $33.6 million for 2020. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $17.0 million in 2021 and $14.0 million in 2020.

Trade receivables include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short-term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $14.6 million in 2021 and $18.9 million in 2020. DPA receivable balances at December 31 were $22.0 million in 2021 and $25.7 million in 2020.

***Debentures, bonds and bank borrowings*:** We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our balance sheets.

Inventory: Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our balance sheets within "Fuel and natural gas in storage."

We also have materials and supplies inventories that we use for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on our balance sheets within "Materials and supplies." We combine inventory items for the statement of cash flow presentation purposes.

In addition, stand-alone renewable energy credits that are generated or purchased and held for sale are recorded at the lower of cost or net realizable value and are reported on our balance sheets within "Materials and supplies."

Government grants: We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in the period in which we incur the expenses.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them to earnings when revenue recognition criteria are met.

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos, polychlorinated biphenyl-contaminated equipment, gas pipeline, and cast iron gas mains and electricity generation facilities. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity’s control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, for the years ended December 31, 2021 and 2020.

Years Ended December 31,		**2021**		**2020**
(Thousands)				
ARO, beginning of year	$	2,562	$	2,713
Liabilities settled during the year		(267)		(295)
Accretion expense		135		144
ARO, end of year	**$**	**2,430**	**$**	**2,562**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

***Accrued removal obligations*:** We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

***Environmental remediation liability*:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2060.

***Post-employment and other employee benefits*:** We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the NYPSC. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes**:** AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, RG&E settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax receivable balance due from AGR at December 31 is $3.6 million for 2021 and $26.3 million for 2020.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2021 and 2020.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is not more likely than not that we will realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current in our balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in “Taxes other than income taxes” and “Taxes accrued” in our financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in the statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Limited voting junior preferred stock: We have a class of preferred stock having one share and a par value of $1, which is issued and outstanding and has voting authority only with respect to whether RG&E may file a voluntary bankruptcy petition.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation; (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments; and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for: (1) franchise taxes that are partially based on income; (2) transactions with a government that result in a step up in the tax basis of goodwill; (3) separate financial statements of legal entities that are not subject to tax; and (4) enacted changes in tax laws in interim periods. We adopted the amendments effective January 1, 2021, with no material effect to our results of operations, financial position, cash flows and disclosures. We are applying the amendments on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment requirement.

(b) Improvements to lessor accounting for certain leases with variable lease payments

In July 2021, the FASB issued amendments to make targeted improvements to ASC 842 for lessor's accounting for certain leases with variable lease payments, which affect lease classification. The amendments require a lessor to classify and account for a lease with variable lease payments as an operating lease if (a) the lease would have been classified as a sales-type lease or a direct financing lease and (b) the lessor would have otherwise recognized a day-one loss. The amendments are effective for fiscal years beginning after December 15, 2021, for all entities, and interim periods within those fiscal years for public business entities, with early application permitted. We have elected to early apply the amendments effective October 1, 2021, and apply the amendments prospectively to leases that commence or are modified on or after that date. Our adoption does not materially affect our results of operations, financial position and cash flows.

(c) Accounting for revenue contracts with customers acquired in a business combination

In October 2021, the FASB issued amendments related to the accounting for revenue contracts acquired in a business combination. The amendments require an entity (acquirer) to recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606, Revenue from Contracts with Customers. At the acquisition date, an acquirer should account for the related revenue contract in accordance with ASC 606 as if it had originated the contracts. Generally, this should result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree's financial statements. The amendments also provide certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. For public business entities, the amendments are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The amendments should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted. We have elected to early apply the amendments effective October 1, 2021. Our adoption did not materially affect our results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2021, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments were effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Our prospective adoption of ASC 848 on January 1, 2022 will not materially affect our results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

In November 2021, the FASB issued amendments that apply to business entities (all entities except specified not-for-profit entities and employee benefit plans) that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance (such as a grant model within International Accounting Standards 20 Accounting for Government Grants and Disclosure of Government Assistance, or ASC Subtopic 958-605, Not-For-Profit Entities—Revenue Recognition). Government assistance can include tax credits (excluding transactions within the scope of Topic 740, Income Taxes), cash grants, grants of other assets, and project grants. Often, government assistance is provided to an entity for a particular purpose, and the entity promises to take specific actions. Transactions with a government, as used in ASC 832, Government Assistance, include assistance administered by domestic, foreign, local (city, town, county, municipal), regional (state, provincial, territorial), and national (federal) governments and entities related to those governments. The amendments require annual disclosures in notes to financial statements about transactions with a government as follows: (1) information about the nature of the transactions and the related accounting policy used to account for the transactions, (2) the line items on the balance sheet and income statement affected by the transactions, and the amounts applicable to each financial statement line item, and (3) significant terms and conditions of the transactions, including commitments and contingencies. For entities within scope the amendments are effective for annual periods beginning after December 15, 2021, with early application permitted. The amendments are to be applied either (1) prospectively to transactions within the scope of the amendments that are reflected in financial statements at the date of initial application and new transactions that are entered into after the date of initial application or (2) retrospectively to those transactions. Our adoption of the amendments on January 1, 2022 will not materially affect our disclosures.

***Use of estimates and assumptions*: ** The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) earnings sharing mechanisms; (10) environmental remediation liabilities; (11) AROs; and (12) pension and other postretirement employee benefits. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 48% of our employees are covered by a collective bargaining agreement. Agreements expiring in the coming year apply to approximately 11% of our employees.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the NYPSC. The tariffs are applied to regulated activities and are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflects our capital ratio and a reasonable return on equity (ROE).

Energy costs that are set on the New York wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred by the utilities is offset by applying reconciliation procedures that result in either immediate or deferred tariff adjustments. Reconciliation procedures apply to other costs, which are in many cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers. Revenues that allow us to exceed target returns, usually the result of better than expected cost efficiency, are generally shared with our customers, resulting in future tariff reductions.

RG&E Rate Plan

On May 20, 2019, RG&E filed rate cases requesting increases in delivery revenues for both its electric and gas businesses. Other parties to the rate cases filed direct testimony on September 20, 2019, and RG&E filed rebuttal testimony on October 15. The Administrative Law Judges in the cases agreed to a series of extensions of the litigation schedule to allow the Company, the Department of Public Service Staff ("DPS Staff"), and other parties to enter into and conduct settlement discussions. A Joint Proposal for a three-year rate plan term was filed on June 22, 2020. A modified Joint Proposal was approved by the NYPSC on November 19, 2020, which included modifications to the electric business proposed rate increases to limit the projected total bill increases to 2% per year in consideration of the current COVID-driven economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The approved Joint Proposal includes several COVID-19 provisions, including the provision of up to $13.5 million in bill credits for the Company's most vulnerable residential and small business customers. The Joint Proposal bases delivery revenues on an 8.80% ROE and 48% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50%. The approved Joint Proposal was signed in whole or in part by more than 20 parties, and includes delivery rate increases (excluding the impact of moving energy efficiency costs from a surcharge to delivery rates) as summarized below:

	May 1, 2020		May 1, 2021		May 1, 2022	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$16.8	3.8%	$13.9	3.2%	$15.8	3.3%
Gas	$0.0	0.0%	$0.0	0.0%	$2.4	1.3%

The approved Joint Proposal also reflects increased distribution vegetation management, investments in aging infrastructure, the implementation of Advanced Metering Infrastructure (AMI), and increases in the Company's workforce, as well as continuation of many of the components of the last Joint Proposal described above. The rate plans continue the Rate adjustment mechanism (RAM) designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue RDMs for each business. The Proposal also continued reserve accounting for qualifying Major Storms ($3.4 million annually). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds for each storm event.

The approved Joint Proposal maintained electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The Proposal also maintained certain gas safety performance measures at the company, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The approved Joint Proposal established threshold performance levels for designated aspects of customer service quality and continues bill reduction and arrears forgiveness Low Income Programs. Reforming the Energy Vision (REV)-related incremental costs and fees will be included in the RAM to the extent cost recovery is not provided for elsewhere. Under the approved Joint Proposal, RG&E continues the RAM, which is applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; (5) COVID-19 bill credits; (6) certain Electric Vehicle program costs; and (7) Energy Efficiency and Heat Pump program costs in excess of what is included in delivery rates.

The Proposal provided for partial or full reconciliation of certain expenses including, but not limited to: pension and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; Major Storms; nuclear electric insurance limited credits; economic development; and Low Income Programs. The Proposal also includes downward-only Net Plant reconciliations. In addition, the Proposal included downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provided that we continue the electric RDMs on a total revenue per class basis and modify the gas RDMs to a total revenue per class basis instead of the previous revenue per customer basis.

Reforming the Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV, which is a wide-ranging initiative to reform New York State’s energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV and its related proceedings have and will continue to propose regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

In 2015, the NYPSC issued an order in Track 1, which acknowledges the utilities’ role as a Distribution System Platform (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016, followed by bi-annual updates. The companies filed the initial DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. The companies filed their required bi-annual updates of the DSIP on July 31, 2018 and June 30, 2020. The next bi-annual update is scheduled for June 2022.

Other various proceedings have also been initiated by the NYPSC which are REV related, and each proceeding has its own schedule. These proceedings include the Clean Energy Standard, Value of Distributed Energy Resources (VDER) and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all load serving entities were ordered to begin payments to New York State Energy Research and Development Authority (NYSERDA) for Renewable Energy Credits (“RECs”) and Zero Emissions Credits (ZECs) beginning in 2017. NYSEG and RG&E collect costs associated with RECs and ZECs through electric supply charges. A separate Offshore Wind proceeding was ordered by the NYPSC in July 2018, setting a goal of 2,400 MW of offshore wind capacity in New York State by 2030. Initial procurement solicitations by NYSERDA in 2018 and 2019 secured 1,696 MW of offshore wind. On January 28, 2020, NYSERDA filed a petition seeking authorization to conduct an additional procurement in 2020 for 1,000 MW or more of offshore wind, with the flexibility to evaluate a range of bids for up to 2,500 MW In an order issued April

23, 2020, the Commission authorized NYSERDA to issue an additional offshore wind solicitation in 2020 for 1,000 MW or more.

A Track 2 order was issued in May 2016 and included guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections, and Clean Air. A collaborative process to review the companies' petition began in the first quarter of 2017 and was suspended in the third quarter of 2017. A proposal for EAMs was included in the companies' May 20, 2019 rate filing and is reflected in the recently approved Rate Plan.

In March 2017, the NYPSC issued three separate REV-related orders. The three orders involve: 1) modifications to the electric utilities' proposed interconnection EAM framework; 2) further DSIP requirements, including the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at RG&E by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the VDER. In September 2017, the NYPSC issued an order related to the VDER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing. NYSEG and RG&E submitted biannual updates of the DSIP on July 31, 2018 and June 30, 2020 consistent with guidance received from the NYPSC. RG&E has participated with the other NY state electric utilities in jointly filing updates to the interconnection earnings adjustment mechanism, has implemented two energy storage projects, and has participated with the other NY state electric utilities in the VDER transition effort, including tariff updates and application of VDER principles.

The March 2017 Order in the VDER proceeding approved a transition from traditional Net Energy Metering (NEM) towards a more value-based approach (Value Stack) for compensating Distributed Energy Resources (DER). The March 2017 Order approved an interim methodology for more precise DER valuation and compensation for NEM-eligible technologies. The interim methodology approved by the NYPSC provided for a market transition consistent with the principles of gradualism and predictability and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceeding. Phase Two would encompass improvements to the interim methodology established in Phase One, seek to expand Value Stack eligibility to technologies not included in Phase One, and review rate designs for mass market (i.e., residential and small non-residential) on-site DERs whose project would be interconnected after January 1, 2020. Working groups were established for further discussions regarding Value Stack, Rate Design and Low Income. The working groups met toward the latter half of 2017 and all of 2018 to discuss, review and analyze several issues regarding each subject. The working groups culminated with a series of whitepapers developed by DPS Staff, addressing: a) Standby and Buyback Service Rate Design, b) Future Value Stack Compensation, and c) Capacity Value Compensation. The whitepapers were submitted between December 12 and December 14, 2018 in the VDER proceeding.

The March 2017 Order stated that should a new compensation methodology not be in place by January 1, 2020, mass market projects put into service after that date would receive NEM compensation only until the new compensation methodology is developed and implemented and would then be transferred to the new compensation methodology. On December 9, 2019, DPS Staff filed a whitepaper on rate design for mass market NEM successor tariffs. DPS Staff recommended the continuation of NEM as a compensation mechanism for all eligible mass market and commercial DER projects under 750 kW. Staff also proposed that these projects should be eligible for the range of options currently provided in delivery rates. For projects with load profiles or expertise that may benefit from time-varying price signals, projects would have the option to forego the use of standard delivery rates and instead utilize more sophisticated time-of-use (TOU) or new mass market standby rates, coupled with a modest charge to collect public benefit funds that are otherwise avoided by using NEM. On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022,and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 shall be charged a monthly per kW fee based on the nameplate rating of the DER. Draft tariff leaves implementing the Commission's Order and proposed CBC calculations were filed on November 1, 2020, and a technical conference was held on March 25, 2021 to review the utilities' calculations. A final Commission Order was issued on August 13, 2021, implementing the CBC effective January 1, 2022 for new mass market net metering customers.

On April 18, 2019, the Commission issued an Order on Future Value Stack Compensation and Capacity Value Compensation. The Order established a new Community Credit in place of the Market Transition Credit for certain CDG projects in NYSEG's and RG&E's service territories and expanded eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower. The changes became effective on June 1, 2019. On December 12, 2019, the NYPSC issued an Order Regarding Consolidated Billing For Community Distributed Generation. This Order led to CDG subscription charges being on the RG&E bill along with the CDG subscription credits, resulting in easier billing for customers and lower billing and service costs for CDG Hosts. Also on December 12, 2019, the NYPSC issued an Order on Value Stack Compensation for High-Capacity-Factor Resources, modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding Value Stack Compensation. The Order directed National Grid, NYSEG, and RGE to reallocate capacity from closed tranches where available capacity remained due to projects being canceled since the issuance of the VDER Compensation Order, and to assign that capacity to a new Community Credit Tranche with compensation at 2 cents per kWh. The utilities must also continue to reallocate capacity to this new Tranche for the next six months when there are cancellations of projects that have received a Market Transition Credit or Community Credit allocation. The new provisions per the March 19, 2020 Order became effective May 1, 2020. As eligible projects are interconnected, each project will receive MTC or Community Credit compensation for kWh produced, and the dollars provided to each project for this compensation will ultimately be collected from customers in a future surcharge.

The April 18, 2019 Order also initiated a new proceeding to examine utilities' marginal cost of service studies. An initial meeting in that proceeding was held on June 28, 2019, during which the utilities explained their various marginal cost methodologies. DPS Staff will develop a whitepaper addressing the utilities' marginal cost studies with recommendations on how such studies shall be subsequently performed. To aid in the development of the whitepaper, Staff requested preliminary comments from stakeholders by November 25, 2019, and additional information from the Utilities in February 2020 regarding their marginal cost methodologies. At this time it is not known when the DPS Staff whitepaper on marginal cost methodologies will be issued.

On May 16, 2019, the Commission issued an Order on Standby and Buyback Service and Establishing Optional Demand Rates. The Order expands the availability of demand rates based on standby service rate design principles by requiring utilities to file tariffs to provide opt-in eligibility for all customers, including mass market (i.e., residential), to a demand-based rate option, irrespective of whether customers have on-site DERs. The availability of existing standby rates was expanded to all current demand-billed customers on an optional basis beginning July 1, 2019. Optional standby rates for mass market customers will be made available in the near future. RG&E filed draft tariffs on September 23, 2019 as required, with further analysis and discussion regarding approval and implementation of the optional rates occurring through the Rate Design Working Group of the VDER proceeding. On November 25, 2020 DPS Staff, jointly with NYSERDA, issued a whitepaper on further recommendations regarding standby and buyback rates that were based on the electric utilities' September 23, 2019 filings. Comments on the recommendations in the whitepaper were submitted on March 8, 2021, and reply comments were submitted on April 12, 2021. A technical conference was held on July 22, 2021, and an additional comment period was established for August 20, 2021. A Commission Order is expected in 2022.

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited customers. Stakeholders subsequently requested residential customers be permitted to participate as remote crediting satellites and the frequency of credit allocation and adding/removing satellites be increased to allow for monthly changes rather than annual changes only. Tariffs were filed on August 16, 2021, becoming effective on September 1, 2021. The result of this Order reshaped an existing program and the impact to the Companies should be minimal.

On April 24, 2018, the Commission instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the adoption of electric vehicles and expansion of electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, and subsequently clarified its Order on July 12, 2019 and March 3, 2020. A Whitepaper was issued by DPS Staff on January 13, 2020, proposing a make-ready infrastructure program with a budget estimated at $582 million. An order in this proceeding was issued by the Commission on July 16, 2020, approving a $700 million statewide program (NYSEG and RG&E combined share is approximately $118 million) funded by customers to accelerate the deployment of electric vehicle charging stations in an effort to increase the number of electric vehicles.

On February 11, 2021, the Commission issued an Order to implement an Integrated Energy Data Resource platform, where NYSERDA was designated as the Program Sponsor of the platform. The development of the platform will be an iterative process, currently separated into two phases. Utilities will be expected to transmit data to the platform through processes to be established with the Program Manager (to be determined). The Order established a combined cost cap of $12 Million for NYSEG and RG&E for Phase 1, to be deferred and recovered in the next rate case filing after Phase 1 is complete. On April 15, 2021, the Commission issued an Order Adopting a Data Access Framework and Establishing Further Process ("DAF Order"). The DAF Order establishes a centralized data access certification process. On May 14, 2021, a stakeholder (Mission:data Coalition) filed a petition for rehearing on the DAF Order citing concerns with the audit requirements. The NY utilities also jointly filed a petition for rehearing on May 17, 2021 regarding the Commission's directive to remove fees for certain requests for data. The Commission issued an Order on November 18, 2021 denying both requests for rehearing.

On December 13, 2018, the Commission issued an Order for RG&E to file an implementation plan detailing a competitive procurement process and cost recovery for deploying 10 MW of qualified storage systems. RG&E filed its implementation plan and has issued requests for proposals to site storage systems within their service territory. On April 16, 2021, the Commission issued an Order to modify the term offered to developers for energy storage contracts and extended the in-service date for deployment of the 10 MW of energy storage. The Companies have tariffs in effect to collect costs for the procurement of qualified energy storage assets.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2018 Winter Storms

In March 2018, following two severe winter storms that impacted over more than a million electric utility customers in New York, including 520,000 NYSEG and RG&E customers, the New York Department of Public Service ("NYDPS") initiated a comprehensive investigation of all the New York electric utilities' preparation and response to those events. The investigation was expanded to include other 2018 New York spring storm events.

On April 18, 2019 the NYDPS staff issued a report (the "2018 Staff Report") of the findings from their investigation. The 2018 Staff Report identifies 94 recommendations for corrective actions to be implemented in the utilities' Emergency Response Plans ("ERPs"). The 2018 Staff Report also identified potential violations by several of the utilities, including NYSEG and RG&E.

Also on April 18, 2019, the NYPSC issued an Order Instituting Proceeding and to Show Cause directed to all major electric utilities in New York, including NYSEG and RG&E. The order directed the utilities, including NYSEG and RG&E, to show cause why the NYPSC should not pursue civil penalties, and / or administrative penalties for the apparent failure to follow their respective ERPs as approved and mandated by the NYPSC. The NYPSC also directed the utilities to address whether the NYPSC should mandate, reject or modify in whole or in part, the 94 recommendations contained in the 2018 Staff Report. On May 20, 2019, NYSEG and RG&E responded to the portion of the Order to Show Cause with respect to the recommendations contained in the 2018 Staff Report. The Commission granted the companies a series of extensions through December 31, 2019 to respond to the portion of the Order to Show Cause with respect to why the NYPSC should not pursue a penalty action. A joint settlement agreement to avoid litigation including NYSEG and RG&E's agreement to pay a penalty of $10.5 million (allocated as $9.0 million to NYSEG and $1.5 million to RG&E) was filed with the NYPSC on December 17, 2019. On February 6, 2020, the NYPSC approved the joint settlement agreement, and the penalty amount is reflected as a rate moderator in the recently approved Joint Proposal.

NYDPS Investigation of the Preparation for and Response to the Tropical Storm Isaias

On August 5, 2020, the NYDPS commenced an investigation into the preparation for and response to the Tropical Storm Isaias by several utilities in New York including RG&E. In addition, the New York State Senate and Assembly held a joint hearing to examine the response of various utility companies during the aftermath of Tropical Storm Isaias. The investigation is ongoing. In August, 2020, the Company received a letter from the NYDPS requesting a series of follow-on actions, which the Company has completed or is in the process of completing. At its November 19, 2020 session, the NYPSC provided an interim status report on the investigation and RG&E was not identified in the report other than to acknowledge the letter regarding follow-on actions that had been received by the Company. We cannot predict the final outcome of this investigation.

New York State Public Service Commission Show Cause Order Regarding Greenlight Pole Attachments

On November 20, 2020, the NYPSC issued an Order Instituting Proceeding and to Show Cause (the Show Cause Order) regarding alleged violations of the NYPSC's 2004 Order Adopting Policy Statement on Pole Attachments, dated August 6, 2004 (the 2004 Pole Order) by RG&E, Greenlight Networks, Inc, (Greenlight), and Frontier Communications (Frontier). The alleged violations detailed in the Show Cause Order arise from Greenlight's installation of unauthorized and substandard communications attachments throughout RG&E's and Frontier's service territories. The Show Cause Order directs RG&E to show cause within 30 days why the NYPSC should not pursue civil and/or administrative penalties or initiate a prudency proceeding or civil action for injunctive relief for more than 11,000 alleged violations of the 2004 Pole Order. Under NY Public Service Law Section 25-a, each alleged violation carries a potential penalty of up to $100,000 where it can be shown that the violator failed to "reasonably comply" with a statute or NYPSC order.

RG&E, Greenlight and Frontier filed respective notices to initiate settlement negotiations with respect to the alleged violations and to extend the deadline for filing a response to the Show Cause Order. The NYPSC granted the extension requests initiating settlement discussions. On August 12, 2021, the NYPSC approved a settlement entered into by NYDPS and RG&E providing for, among other things, RG&E's payment of $2.5 million, which was deposited in a required escrow account in January 2022 and which will be used to support the State of New York's broadband initiative for underserved areas. This settlement amount could increase to a maximum of $5 million if RG&E does not resolve certain identified safety violations caused by Greenlight's pole attachments on or before December 31, 2021. We have met all compliance requirements of the settlement and filed status reports with the NYPSC in the fourth quarter of 2021 and in January 2022 reflecting this compliance. We cannot predict the final outcome of this matter.

Minimum Equity Requirements for Regulated Subsidiaries

RG&E is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, RG&E must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, RG&E must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. RG&E is prohibited by regulation from lending to unregulated affiliates. RG&E has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $106.7 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of regulatory assets and regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

On November 19, 2020, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at RG&E effective April 17, 2020. Following the approval of the proposal RG&E's plant related tax items are amortized over the life of associated plant, and unfunded deferred taxes being amortized over a period of forty-six years. A majority of the other items related to RG&E will be amortized over a five-year period. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, net annual amortization revenue for RG&E is approximately $66.3 million for the year ended December 31, 2021.

Current and non-current regulatory assets at December 31, 2021 and 2020 consisted of:

December 31,	2021	2020
(Thousands)		
Current		
Decommissioning	$ 676	$ 676
Delivery Rate Shaping	23,853	—
Electric Supply Reconciliation	3,835	821
Federal tax depreciation normalization adjustment	1,413	1,413
Hedge losses	—	6,879
Low income program	1,393	1,393
Pension and other postretirement benefits cost deferrals	7,388	7,388
Post Term Amortization	904	904
Rate adjustment mechanism	6,958	1,345
REV demand response	1,003	1,003
Revenue decoupling mechanism	14,165	13,898
Storm costs	9,804	9,804
Value of Distributed Energy Resources Program	3,168	879
Other	2,899	2,892
Total current regulatory assets	**$ 77,459**	**$ 49,295**
Non-current		
Asset retirement obligation	$ 3,206	$ 3,203
COVID-19 uncollectible deferral	1,671	—
Decommissioning	828	1,546
Environmental remediation costs	64,085	53,841
Federal tax depreciation normalization adjustment	43,577	45,001
Low income program	11,011	8,363
Pension and other postretirement benefits	24,986	69,590
Pension and other postretirement benefits cost deferrals	15,671	25,064
Post term amortization	2,109	3,013
Rate adjustment mechanism	6,313	589
Storm costs	37,650	43,912
Unamortized losses on reacquired debt	4,120	4,564
Unfunded future income taxes	143,424	136,389
Other	18,589	18,723
Total non-current regulatory assets	**$ 377,240**	**$ 413,798**

Asset retirement obligations represent the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

COVID-19 uncollectible deferral represents deferred COVID-19 related costs.

Decommissioning represents amounts to be collected in rates for the decommissioning of shut down plants.

Delivery rate shaping represents the NY delivery rate levelization to smooth the rate increase across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates The amortization period in current rates is five years and began in 2020.

Electric supply reconciliation represents over/under collection of costs related to electric supply in which RG&E supplies electricity as the default service option for customers.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is seven years and began in 2020. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Powertax deferred income tax. It is being amortized over a thirty-five year period starting in 2020.

Hedge losses represents deferred fair value losses on electric and gas hedge contracts.

Low income programs represent various hardship and payment plan programs approved for recovery. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base.

Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Post term amortization represents the amortization costs deferred from previous rate cases. It is being amortized over a five-year period starting in 2020.

Rate adjustment mechanism (RAM) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but this also includes property taxes and REV costs and fees not covered in other recovery mechanisms.

REV demand response are the costs associated with the Reforming the Energy Program to rapidly develop and scale a clean and resilient energy economy, yet keep affordability for customers.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. RG&E is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Value Distributed Energy Resource represents a mechanism to compensate energy created by distributed energy resources, like solar.

Other includes items such as gas supply reconciliation and unamortized loss on reacquired debt.

Deferred income taxes regulatory: see Note 1.

Current and non-current regulatory liabilities at December 31, 2021 and 2020 consisted of:

December 31,		2021		2020
(Thousands)				
Current				
Asset sale gain account	$	1,827	$	5,444
Carrying costs on deferred income tax bonus depreciation		10,984		8,114
Debt rate reconciliations		8,683		5,670
Delivery rate shaping		—		8,165
Earnings sharing		2,106		2,106
Economic development		3,000		3,000
Energy efficiency programs		8,240		6,335
Environmental remediation costs		7,509		7,509
Gas supply charge		623		1,898
Hedge Gains		9,262		—
Merchant function charge		100		—
Mixed use 263(a)		1,236		1,236
Net plant reconciliation		4,534		4,520
Nine Mile II - TCC		4,229		4,229
Positive benefit adjustment		6,528		6,528
Property tax		6,939		6,939
Reliability support services		1,618		1,528
Tax Act – remeasurement		13,308		18,231
Unfunded future income taxes		3,124		3,124
Other		7,951		8,952
Total current regulatory liabilities	**$**	**101,801**	**$**	**103,528**
Non-current				
Accrued removal obligations	$	197,909	$	192,794
Asset sale gain account		—		1,827
Carrying costs on deferred income tax bonus depreciation		8,818		19,854
Debt rate reconciliations		8,485		19,057
Deferred property taxes		9,866		17,651
Deferred transmission congestion contracts		18,508		17,739
Delivery Rate Shaping		57,848		—
Earnings sharing		7,009		8,997
Economic development		15,769		17,373
Energy efficiency programs		14,708		21,599
Merger capital expense		2,778		3,969
NEIL (Nuclear Electric Insurance Limited) credits		9,237		9,606
Net plant reconciliation		10,875		15,392
Pension and other postretirement benefits		6,636		2,080
Pension and other postretirement benefits cost deferrals		1,495		1,185
Positive benefit adjustment		15,231		21,759
Tax Act – remeasurement		257,751		271,217
Theoretical reserve flow through impact		2,930		4,186
Other		49,850		57,521
Total non-current regulatory liabilities	**$**	**695,703**	**$**	**703,806**

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Asset sale gain account represents the net gain on the sale of certain assets that will be used for the future benefit of customers. The amortization period in current rates is two years for RG&E and began in 2020.

Carrying costs on deferred income tax bonus depreciation represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. The amortization period is five years following the approval of the proposal by the NYPSC.

Debt rate reconciliations represent the over/under collection of costs related to fixed and variable rate debt instruments identified in the rate case. Costs would include interest, commissions and fees versus amounts included in rates.

Deferred property taxes represent the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The amount is being amortized over a five-year period following the approval of the proposal by the NYPSC.

Deferred transmission congestion contracts represent the deferral of the right to collect day-ahead market congestions rents going forward in time.

Delivery rate shaping represents the NY delivery rate levelization to smooth the rate increase across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates The amortization period in current rates is five years and began in 2020.

Earning sharing provisions represents the annual earnings over the earning sharing threshold. The amortization period in current rates is five years and began in 2020.

Economic development represents the economic development program which enables RG&E to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to RG&E varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

Energy efficiency programs standard represents the difference between revenue billed to customers through an energy efficiency charge and the costs of our energy efficiency programs as approved by the state authorities.

Gas supply charge reflects the actual cost of purchasing, transporting and storing natural gas for those customers who receive their natural gas supply from RG&E.

Hedge gains represents deferred fair value gains on electric and gas hedge contracts.

Merchant function charge reflects the administrative costs of obtaining natural gas supply. Customers with a supplier other than RG&E are not charged for this service.

Merger capital expense target customer credit account was created as a result of RG&E not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is five years following the approval of the proposal by the NYPSC.

Mixed services 263(a) represent the carrying costs benefit of increased accumulated deferred income taxes created by Section 263(a) IRC. The amortization period in current rates is three years and began in 2020.

NEIL (Nuclear Electric Insurance Limited) credits represents the difference between insurance credit amounts reflected in rates and actual credits received.

Net plant reconciliation represents the reconciliation of the actual electric and gas net plant and book depreciation to the targets set forth in the Joint Proposal. The amortization period in current rates is five years and began in 2020.

Nine Mile transmission congestion contracts represents deferral of the Nine Mile 2 Nuclear Plant transmission congestion contract at RG&E. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of AVANGRID (formerly Energy East Corporation). The amortization period in current rates is five years and began in 2020.

Property tax represents the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The amount is being amortized over a five-year period following the approval of the proposal by the NYPSC.

Rate adjustment mechanism (RAM) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but this also includes property taxes and REV costs and fees not covered in other recovery mechanisms.

Reliability support services represents the deferral of costs associated with keeping units available and capable of being committed for reliability purposes as requested by the utility or the NYISO.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The amortization period in current rates is from one and half to ten years and began in 2020.

Other includes items such as asset retirement obligations, other taxes, and vegetation management.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

RG&E derives its revenue primarily from tariff-based sales of electricity and natural gas service to customers in New York with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity and natural gas.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. In New York, customers have the option to obtain the electricity or natural gas commodity directly from the utility or from another supplier. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity or natural gas provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the NYISO or PJM Interconnection, LLC (PJM), as applicable. Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as RG&E delivers or sells the electricity or natural gas or provides the transmission service.

RG&E records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. The RG&E ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

RG&E also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period, and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years. TCC contract liabilities totaled $0.5 million at December 31, 2021, and $0.6 million at December 31, 2020, and are presented in "Other current liabilities" on our balance sheets. We recognized $1.7 million as revenue in 2021 and $1.1 million in 2020.

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for the years ended December 31, 2021 and 2020 are as follows:

Years Ended December 31,		**2021**		**2020**
(Thousands)				
Regulated operations – electricity	$	643,228	$	590,201
Regulated operations – natural gas		288,759		255,556
Other (a)		9,024		11,832
Revenue from contracts with customers		**941,011**		**857,589**
Leasing revenue		61		70
Alternative revenue programs		13,958		17,021
Other revenue		2,759		(2,737)
Total operating revenues	**$**	**957,789**	**$**	**871,943**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,		**2021**		**2020**
(Thousands)				
Current				
Federal	$	(9,200)	$	5,733
State		(2,544)		(2,755)
Current taxes charged to (benefit) expense		**(11,744)**		**2,978**
Deferred				
Federal		21,238		7,608
State		9,939		9,049
Deferred taxes charged to expense		**31,177**		**16,657**
Total Income Tax Expense	**$**	**19,433**	**$**	**19,635**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2021 and 2020, respectively, consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Tax expense at federal statutory rate	$ 25,687	$ 27,957
Equity AFUDC tax impacts not normalized	(2,303)	(4,052)
Excess ADIT amortization	(9,728)	(6,418)
State tax expense, net of federal benefit	5,842	4,972
Other, net	(65)	(2,824)
Total Income Tax Expense	**$ 19,433**	**$ 19,635**

Income tax expense for the year ended December 31, 2021 was $6.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Equity AFUDC tax effects, partially offset by state tax expense. This resulted in an effective tax rate of 15.9%. Income tax expense for the year ended December 31, 2020 was $8.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Equity AFUDC tax effects, partially offset by state tax expense. This resulted in an effective tax rate of 14.7%.

In 2020, RG&E began refunding previously deferred protected and unprotected Excess ADITs, established as a result of the 2017 Tax Act as part of the 2020 Joint Proposal and as determined by the NYPSC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2021 and 2020 consisted of:

December 31,	2021	2020
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 531,933	$ 491,224
Unfunded future income taxes	35,653	33,045
Storms	15,776	14,184
Regulatory liability due to "Tax Cuts and Jobs Act"	(70,842)	(75,648)
Pension and other postretirement benefits	(21,817)	(18,134)
Derivative assets	(11,659)	(12,640)
Environmental	(11,253)	(13,033)
Federal and state net operating loss	(14,053)	(4,436)
Other	(37,515)	(49,441)
Total Non-current Deferred Income Tax Liabilities	**$ 416,223**	**$ 365,121**
Deferred tax assets	$ 167,139	$ 173,332
Deferred tax liabilities	583,362	538,453
Net Accumulated Deferred Income Tax Liabilities	**$ 416,223**	**$ 365,121**

RG&E has gross federal net operating losses of $27.7 million and gross New York state net operating losses of $157.9 million for the year ended December 31, 2021. RG&E has gross federal net operating losses of $4.1 million and gross New York state net operating losses of $69.7 million for the year ended December 31, 2020.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Beginning Balance	$ 49,387	$ 49,674
Reduction for tax positions related to prior years	(287)	(287)
Ending Balance	**$ 49,100**	**$ 49,387**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2021 and December 31, 2020.

Note 6. Long-term Debt

Long-term debt as of December 31, 2021 and 2020 consisted of:

As of December 31,		2021		2020	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2025-2051	$ 1,285,500	1.85%-8.00%	$ 1,160,500	3.10%-8.00%
Unsecured pollution control notes - fixed	2025	91,900	3.00%	91,900	2.875%-3.00%
Unamortized debt issuance cost and discount		(11,232)		(10,526)	
Total Debt		**1,366,168**		**1,241,874**	
Less: debt due within one year, included in current liabilities		—		123,738	
Total Non-current Debt		**$ 1,366,168**		**$ 1,118,136**	

(a) The first mortgage bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service. We have no other secured indebtedness. None of our other debt obligations are guaranteed or secured by any of our affiliates.

On November 23, 2020, RG&E issued $200 million aggregate principal amount of first mortgage bonds maturing in 2030 at an interest rate of 1.85%.

On December 15, 2021, RG&E issued $125 million aggregate principal amount of first mortgage bonds maturing in 2031 at an interest rate of 2.10%, as well as $125 million aggregate principal amount of first mortgage bonds maturing in 2051 at an interest rate of 2.91%.

Long-term debt, including sinking fund obligations, due over the next five years consist of:

2022	2023	2024	2025	2026	Total
(Thousands)					
$ —	$ —	$ —	$ —	$ 152,400	$ 152,400

We have no financial debt covenant requirements related to our long-term debt at December 31, 2021 and 2020.

Note 7. Bank Loans and Other Borrowings

RG&E had $53.5 million of notes payable outstanding as of December 31, 2021 and no notes payable outstanding as of December 31, 2020. RG&E funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility), and a bank provided credit facility to which RG&E is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E has a lending/borrowing limit of $100 million under this agreement. RG&E had $21.5 million outstanding under this agreement as of December 31, 2021 and no debt outstanding as of December 31, 2020.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E had $32.0 million outstanding under this agreement as of December 31, 2021 and no debt outstanding as of December 31, 2020.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026.

Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. RG&E had not borrowed under this agreement as of both December 31, 2021 and December 31, 2020.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.52 to 1.00 at December 31, 2021. We are not in default as of December 31, 2021.

Note 8. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 15 years, some of which may include options to extend the leases for up to 30 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

For the Years Ended December 31,	**2021**	**2020**
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 1,003	$ 6,636
Interest on lease liabilities	1,320	1,465
Total finance lease cost	2,323	8,101
Operating lease cost	530	938
Short-term lease cost	87	193
Variable lease cost	377	(103)
Intercompany	61	93
Total lease cost	**$ 3,378**	**$ 9,222**

Balance sheet and other information for the years ended December 31, 2021 and 2020 was as follows:

As of December 31,	2021	2020
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 1,124	$ 1,774
Operating lease liabilities, current	287	142
Operating lease liabilities, long-term	2,253	2,618
Total operating lease liabilities	$ 2,540	$ 2,760
Finance Leases		
Other assets	$ 48,036	$ 47,809
Other current liabilities	3,930	3,692
Other non-current liabilities	43,772	46,379
Total finance lease liabilities	$ 47,702	$ 50,071
Weighted-average Remaining Lease Term (years):		
Finance leases	8.13	8.83
Operating leases	2.25	5.23
Weighted-average Discount Rate:		
Finance leases	2.57 %	2.89 %
Operating leases	2.92 %	3.27 %

Supplemental cash flows information related to leases was as follows:

For the Years Ended December 31,	2021	2020
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 226	$ 455
Operating cash flows from finance leases	$ 1,320	$ 1,101
Financing cash flows from finance leases	$ 3,598	$ 2,436
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$ 1,230	$ 45,138
Operating leases	$ (52)	$ 8

As of December 31, 2021, maturities of lease liabilities were as follows:

(Thousands)	Finance Leases	Operating Leases
Years ending December 31,		
2022	$ 4,956	$ 292
2023	4,834	2,183
2024	22,338	17
2025	1,714	17
2026	1,744	17
Thereafter	17,950	154
Total lease payments	**53,536**	**2,680**
Less: imputed interest	(5,834)	(140)
Total	**$ 47,702**	**$ 2,540**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 9. Commitments and Contingencies

Purchase power and natural gas contracts, including non-utility generators

RG&E is the provider of last resort for customers. As a result, the company buys physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, RG&E is required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The company enters into financial swaps to comply with the hedge requirement for physical electric energy purchases. RG&E also makes purchases from other independent power producers and New York Power Authority (NYPA) under existing contracts or long-term supply agreements in order to comply with the company's Public Utility Regulatory Policies Act (PURPA) purchase obligation.

RG&E satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by each of the companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The company purchases the majority of its natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The company acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The company acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately $48.5 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2021 and $44.7 million in 2020.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

Waste sites

The Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at nine waste sites. The nine sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the nine sites, eight sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and two sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $0.2 million at December 31, 2021, related to eight sites. We have recorded an estimated liability of $5.5 million related to another six sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. It is possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $5.3 million to $6.2 million as of December 31, 2021. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. Any cost will be flowed through to RG&E ratepayers.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our eleven sites where gas was manufactured in the past. In 1994 and 1996 we entered into orders on consent with the NYSDEC. Those orders require us to investigate and, where necessary, remediate all of our eleven sites. All eleven sites are included in the New York Voluntary Clean-up Program.

Our estimate for all costs related to investigation and remediation of the eleven sites ranges from $82.9 million to $115.4 million at December 31, 2021. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $93.9 million at December 31, 2021, and $90.4 million at December 31, 2020. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis and are expected to be paid through the year 2060.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

Commodity price risk*:* Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of December 31, 2021 and 2020 and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2021 and 2020 are as follows:

(Thousands)	Loss or Gain Recognized in Regulatory Assets/ Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	
As of			Years Ended December 31,		
December 31, 2021	Electricity	Natural Gas	2021	Electricity	Natural Gas
Regulatory assets	$ —	$ 154	Purchased power, natural gas and fuel used	$ (8,300)	$ (6,327)
Regulatory liabilities	$ (7,304)	$ (2,632)			
December 31, 2020			2020		
Regulatory assets	$ 6,914	$ 528	Purchased power, natural gas and fuel used	$ 20,084	$ 2,870
Regulatory liabilities	$ —	$ —			

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Years to settle	Mwhs	Dths	Gallons
As of December 31, 2021			
2022	1,429,550	5,820,000	334,700
2023	438,000	890,000	—
As of December 31, 2020			
2021	1,662,800	5,630,000	402,000
2022	540,000	900,000	—

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2021 and 2020, respectively, consisted of:

December 31, 2021	Derivative Assets Current	Derivative Assets Non-current	Derivative Liabilities Current	Derivative Liabilities Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 11,567	$ 2,031	$ 2,305	$ 1,357
Derivative liabilities	(2,305)	(1,357)	(2,305)	(1,511)
	9,262	674	—	(154)
Designated as hedging instruments				
Derivative assets	40	—	12	—
Derivative liabilities	(12)	—	(34)	—
	28	—	(22)	—
Total derivatives before offset of cash collateral	9,290	674	(22)	(154)
Cash collateral receivable	—	—	—	154
Total derivatives as presented in the balance sheet	**$ 9,290**	**$ 674**	**$ (22)**	**$ —**

December 31, 2020	Derivative Assets Current	Derivative Assets Non-current	Derivative Liabilities Current	Derivative Liabilities Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 1,173	$ 754	$ 1,173	$ 754
Derivative liabilities	(1,173)	(754)	(8,052)	(1,317)
	—	—	(6,879)	(563)
Designated as hedging instruments				
Derivative assets	7	—	7	—
Derivative liabilities	(7)	—	(74)	—
	—	—	(67)	—
Total derivatives before offset of cash collateral	—	—	(6,946)	(563)
Cash collateral receivable	—	—	6,879	563
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (67)**	**$ —**

As of both December 31, 2021 and 2020, the derivative assets and derivative liabilities are presented within other current and non-current assets and liabilities of the balance sheet, respectively.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging instruments on OCI and income for the years ended December 31, 2021 and 2020, respectively, consisted of:

Years Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of Loss Reclassified From Accumulated OCI into Income	Loss Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2021				
Interest rate contracts	$ —	Interest expense	$ (3,678)	$ 43,898
Commodity contracts: Other	273	Other operating expenses	178	$ 312,466
Foreign exchange contracts	(22)		—	
Total	**$ 251**		**$ (3,500)**	
2020				
Interest rate contracts	$ —	Interest expense	$ (3,678)	$ 46,186
Commodity contracts: Other	(159)	Other operating expenses	(164)	$ 288,655
Total	**$ (159)**		**$ (3,842)**	

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization at December 31, 2021 is a net loss of $44.6 million as compared to $48.3 million at December 31, 2020. For the year ended December 31, 2021, we recorded $3.7

million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $3.7 million of discontinued cash flow hedges in 2022.

As of December 31, 2021, $0.1 million in gains are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those gains will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

We face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or Standard & Poor's). When our exposure to risk for counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2021 is $0.1 million for which we have posted collateral.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,565 million as of December 31, 2021 and $1,538 million as of December 31, 2020. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

The financial instruments measured at fair value as of December 31, 2021 and 2020 consisted of:

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2021					
Assets					
Derivatives					
Commodity contracts:					
Electricity	$ 10,691	$ —	$ —	$ (3,387)	$ 7,304
Natural Gas	2,907	—	—	(275)	2,632
Other	—	—	40	(12)	28
Total	**$ 13,598**	**$ —**	**$ 40**	**$ (3,674)**	**$ 9,964**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (3,387)	$ —	$ —	$ 3,387	$ —
Natural gas	(429)	—	—	429	—
Other	—	—	(12)	12	—
Foreign exchange contracts	—	(22)	—	—	(22)
Total	**$ (3,816)**	**$ (22)**	**$ (12)**	**$ 3,828**	**$ (22)**

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2020					
Assets					
Derivatives					
Commodity contracts:					
Electricity	$ 1,770	$ —	$ —	$ (1,770)	$ —
Natural Gas	157	—	—	(157)	—
Other	—	—	7	(7)	—
Total	**$ 1,927**	**$ —**	**$ 7**	**$ (1,934)**	**$ —**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (8,684)	$ —	$ —	$ 8,684	$ —
Natural gas	(685)	—	—	685	—
Other	—	—	(74)	7	(67)
Total	**$ (9,369)**	**$ —**	**$ (74)**	**$ 9,376**	**$ (67)**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2021. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

We determine the fair value of our various derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve our electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quotes prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Beginning balance	$ (67)	$ (72)
Realized gains (losses) included in earnings	(178)	164
Unrealized gains (losses) included in other comprehensive income	273	(159)
Ending balance	**$ 28**	**$ (67)**

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 13. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2021 and 2020, consisted of:

(Thousands)	Balance December 31, 2019	2020 Change	Balance December 31, 2020	2021 Change	Balance December 31, 2021
Amortization of pension cost for non-qualified plans, net of tax expense (benefit) of $(159) for 2020 and $169 for 2021	$ (1,662)	$ (1,008)	$ (2,670)	$ 479	$ (2,191)
(Loss) gain on non-qualified pension plans	(54)	54	—	—	—
Unrealized gain (loss) on derivatives qualified as hedges:					
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $(34) for 2020 and $65 for 2021	—	(180)	—	186	
Reclassification adjustment for (gain) loss included in net income, net of income tax expense (benefit) of $35 for 2020 and $(46) for 2021	—	129	—	(132)	
Reclassification adjustment for loss on settled cash flow treasury hedges included in net income, net of income tax expense of $775 for 2020 and $962 for 2021	—	2,903	—	2,716	
Net unrealized (loss) gain on derivatives qualified as hedges	(38,573)	2,852	(35,721)	2,770	(32,951)
Accumulated Other Comprehensive (Loss) Income	**$ (40,289)**	**$ 1,898**	**$ (38,391)**	**$ 3,249**	**$ (35,142)**

Note 14. Postretirement and Similar Obligations

We have funded non-contributory defined benefit pension plans that cover the eligible employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013 the company announced that we would freeze the benefits for all non-union employees covered under the cash balance plans effective December 31, 2013. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for these employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $5.1 million in 2021 and $3.6 million in 2020.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $11.0 million and $12.0 million at December 31, 2021 and 2020, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 392,826	$ 378,559	$ 67,468	$ 65,882
Service cost	5,333	5,696	158	148
Interest cost	6,379	10,574	1,298	1,855
Curtailments/settlements	(12,322)	—	—	—
Actuarial loss/(gain)	(24,132)	33,615	(4,584)	3,082
Benefits paid	(22,949)	(35,618)	(3,315)	(3,499)
Benefit obligation at December 31	**$ 345,135**	**$ 392,826**	**$ 61,025**	**$ 67,468**
Change in plan assets				
Fair value of plan assets at January 1	$ 300,919	$ 286,899	$ —	$ —
Actual return on plan assets	22,565	37,249	—	—
Employer and plan participants' contributions	2,884	12,390	3,315	3,499
Curtailments/settlements	(12,322)	—	—	—
Benefits paid	(22,949)	(35,619)	(3,315)	(3,499)
Fair value of plan assets at December 31	**$ 291,097**	**$ 300,919**	**$ —**	**$ —**
Funded status	**$ (54,038)**	**$ (91,907)**	**$ (61,025)**	**$ (67,468)**

During 2021, the pension benefit obligation had an actuarial gain of $24.1 million, primarily due to a $16.5 million gain from increases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

During 2020, the pension benefit obligation had an actuarial loss of $33.6 million, primarily due to a $35.1 million loss from decreases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2021 and 2020 consisted of:

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Other current liabilities	$ —	$ —	$ (5,084)	$ (5,176)
Pension and other postretirement benefits	(54,038)	(91,907)	(55,941)	(62,292)
Total	**$ (54,038)**	**$ (91,907)**	**$ (61,025)**	**$ (67,468)**

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

December 31,	Pension Benefits 2021	2020	Postretirement Benefits 2021	2020
(Thousands)				
Net loss (gain)	$ 24,986	$ 69,590	$ (4,819)	$ 288
Prior service cost (credit)	—	—	(1,817)	(2,368)

Our accumulated benefit obligation for all qualified defined benefit pension plans was $320.8 million at December 31, 2021 and $364.2 million at December 31, 2020.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all of our qualified plans as of both December 31, 2021 and 2020. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets of our plans as of December 31, 2021 and 2020.

December 31,	2021	2020
(Thousands)		
Projected benefit obligation	$ 345,135	$ 392,826
Accumulated benefit obligation	$ 320,803	$ 364,166
Fair value of plan assets	$ 291,097	$ 300,919

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2021 and 2020.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	2020	Postretirement Benefits 2021	2020
(Thousands)				
Net periodic benefit cost				
Service cost	$ 5,333	$ 5,696	$ 158	$ 148
Interest cost	6,379	10,574	1,298	1,855
Expected return on plan assets	(19,260)	(19,697)	—	—
Amortization of prior service credit	—	—	(550)	(1,390)
Amortization of net loss	16,275	15,454	522	644
Settlement charge	892	—	—	—
Net periodic benefit cost	**$ 9,619**	**$ 12,027**	**$ 1,428**	**$ 1,257**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ (27,437)	$ 16,063	$ (4,584)	$ 3,081
Amortization of net loss	(16,275)	(15,454)	(522)	(644)
Settlement charge	(892)	—	—	—
Amortization of prior service credit	—	—	550	1,390
Total recognized in regulatory assets and regulatory liabilities	(44,604)	609	(4,556)	3,827
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (34,985)**	**$ 12,636**	**$ (3,128)**	**$ 5,084**

We include the service component of net periodic benefit cost in other operating expenses and the non-service component in other income and deductions. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Discount rate	2.31%	1.70%	2.47%	2.00%
Rate of compensation increase	Age-Related / 3.00%	Age-Related Rates	3.00% union	3.00% union
Interest crediting rate	2.00%	2.00%	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Discount rate	1.70%	2.93%	2.00%	2.93%
Expected long-term return on plan assets	7.00%	7.30%	N/A	—
Expected long-term return on plan assets, non-taxable trust	—	—	N/A	6.40%
Expected long-term return on plan assets, taxable trust	—	—	N/A	4.20%
Rate of compensation increase	Age-Related Rates / 3.00% union	3.90%	3.00% union	Age-Related Rates

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

	2021	2020
Health care cost trend rate (pre 65/post 65)	6.50%/7.25%	6.75%/7.50%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029/2027	2029/2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension benefit plan in 2022. We expect to contribute $5.1 million to our postretirement benefit plans during 2022.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2022	$ 33,553	$ 5,084	$ —
2023	$ 32,411	$ 4,929	$ —
2024	$ 30,630	$ 4,740	$ —
2025	$ 29,828	$ 4,555	$ —
2026	$ 28,863	$ 4,398	$ —
2027-2031	$ 125,684	$ 19,189	$ —

Plan assets: Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

Asset Category		Total	Fair Value Measurements at December 31, Using Level 1		Level 2		Level 3
(Thousands)							
2021							
Cash and cash equivalents	$	7,236	$	2,247	$	4,989	$ —
U.S. government securities		15,992		15,992		—	—
Common stocks		13,350		13,350		—	—
Registered investment companies		26,536		26,536		—	—
Corporate bonds		72,492		—		72,492	—
Preferred stocks		78		78		—	—
Common collective trusts		106,497		—		106,497	—
Other investments, principally annuity and fixed income		6,918		1		6,917	—
	$	**249,099**	**$**	**58,204**	**$**	**190,895**	**$ —**
Other investments measured at net asset value		41,998					
Total	**$**	**291,097**					

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

Asset Category		Total	Fair Value Measurements at December 31, Using Level 1		Level 2		Level 3
(Thousands)							
2020							
Cash and cash equivalents	$	13,333	$	10	$	13,323	$ —
U.S. government securities		17,226		17,221		5	—
Common stocks		10,523		10,523		—	
Registered investment companies		29,241		29,241		—	—
Corporate bonds		69,102		—		69,102	—
Preferred stocks		96		96		—	—
Common collective trusts		94,232		—		94,232	
Other investments, principally annuity and fixed income		6,642		617		6,025	—
	$	**240,395**	**$**	**57,708**	**$**	**182,687**	**$ —**
Other investments measured at net asset value		60,524					
Total	**$**	**300,919**					

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.

- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2021 and 2020.

Note 15. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2021 and 2020, consisted of:

Years Ended December 31,		2021		2020
(Thousands)				
Interest and dividend income	$	209	$	87
Allowance for funds used during construction		12,669		20,739
Gain on sale of property		—		15
Carrying costs on regulatory assets		5,593		5,941
Miscellaneous		50		49
Total other income	**$**	**18,521**	**$**	**26,831**
Pension non-service components	$	(5,553)	$	(8,133)
Miscellaneous		(354)		(4,919)
Total other deductions	**$**	**(5,907)**	**$**	**(13,052)**

Note 16. Related Party Transactions

Certain Networks subsidiaries borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including RG&E. For RG&E the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides some administrative and management services to Networks operating utilities, including RG&E, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The cost for services provided to RG&E by AGR and its affiliates was approximately $64.0 million in 2021 and $58.3 million in 2020. Cost for services includes amounts capitalized in utility plant, which was approximately $8.7 million in 2021 and $8.2 million in 2020. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by RG&E to AGR and its subsidiaries was approximately $18.9 million in 2021 and $14.3 million in 2020. All charges for services are at cost. All of the charges associated with services provided are recorded as revenues to offset other operating expenses on the financial statements.

The balance in accounts payable to affiliates of $48.4 million at December 31, 2021 and $16.3 million at December 31, 2020 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $2.9 million at December 31, 2021 and $4.8 million at December 31, 2020 is from various companies.

There were no notes receivable from affiliates at December 31, 2021. Of the balance in notes receivable from affiliates of $19.2 million at December 31, 2020, $11.7 million is from CMP and $7.5 million is from BGC. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

AGR, on behalf of RG&E, guarantees $123 million to fund the clean-up of the Ginna Nuclear Power Plant, LLC.

Note 17. Subsequent Events

The company has performed a review of subsequent events through March 22, 2022, which is the date these financial statements were available to be issued.

The Berkshire Gas Company

Financial Statements

As of and for the Years Ended December 31, 2021 and 2020

The Berkshire Gas Company

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
The Berkshire Gas Company:

Opinion

We have audited the financial statements of The Berkshire Gas Company (the Company), which comprise the balance sheets as of December 31, 2021 and 2020, and the related statements of income, changes in common stock equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

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

Responsibilities of Management for the Financial Statements

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

KPMG LLP

New York, New York
March 31, 2022

The Berkshire Gas Company
Statements of Income

Years Ended December 31,		2021		2020
(Thousands)				
Operating Revenues	$	**85,465**	$	**77,141**
Operating Expenses				
Natural gas purchased		28,901		24,092
Operations and maintenance		31,616		30,054
Depreciation and amortization		8,920		8,172
Taxes other than income taxes, net		6,317		5,221
Total Operating Expenses		**75,754**		**67,539**
Operating Income		**9,711**		**9,602**
Other income		539		301
Other deductions		(2,202)		(1,387)
Interest expense, net of capitalization		(2,806)		(2,928)
Income Before Tax		**5,242**		**5,588**
Income tax expense		879		1,203
Net Income	$	**4,363**	$	**4,385**

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

The Berkshire Gas Company
Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 4,537	$ 212
Accounts receivable and unbilled revenues, net	15,724	14,862
Accounts receivable from affiliates	26	623
Fuel and gas in storage	2,636	2,085
Materials and supplies	1,799	1,309
Other current assets	146	1,967
Regulatory assets	15,916	10,977
Total Current Assets	**40,784**	**32,035**
Utility plant, at original cost	304,225	292,545
Less accumulated depreciation	(100,334)	(97,086)
Net Utility Plant in Service	**203,891**	**195,459**
Construction work in progress	4,619	4,657
Total Utility Plant	**208,510**	**200,116**
Operating lease right-of-use assets	141	—
Other property and investments	2,179	89
Regulatory and Other Assets		
Regulatory assets	22,857	30,119
Goodwill	51,932	51,932
Other	6	2,073
Total Regulatory and Other Assets	**74,795**	**84,124**
Total Assets	**$ 326,409**	**$ 316,364**

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

The Berkshire Gas Company
Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$ —	$ 1,646
Notes payable to affiliates	—	9,010
Accounts payable and accrued liabilities	16,279	12,615
Accounts payable to affiliates	754	861
Interest accrued	729	768
Taxes accrued	7,318	—
Operating lease liabilities	6	—
Regulatory liabilities	198	1,152
Other	4,159	2,042
Total Current Liabilities	**29,443**	**28,094**
Regulatory and Other Liabilities		
Regulatory liabilities	51,908	51,390
Other Non-current Liabilities		
Deferred income taxes	26,803	28,064
Pension and other postretirement	15,472	19,854
Operating lease liabilities	133	—
Environmental remediation costs	3,620	3,950
Other	1,717	2,459
Total Regulatory and Other Liabilities	**99,653**	**105,717**
Non-current debt	59,547	59,498
Total Liabilities	**188,643**	**193,309**
Commitments and Contingencies		
Common Stock Equity		
Additional paid-in capital	116,443	106,095
Retained earnings	21,323	16,960
Total Common Stock Equity	**137,766**	**123,055**
Total Liabilities and Equity	**$ 326,409**	**$ 316,364**

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

The Berkshire Gas Company
Statements of Cash Flows

Years Ended December 31,	2021	2020
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 4,363**	**$ 4,385**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	8,920	8,172
Regulatory assets/liabilities amortization	(22)	612
Regulatory assets/liabilities carrying cost	(212)	—
Amortization of debt issuance costs	50	120
Deferred taxes	(2,099)	2,307
Pension cost	509	2,131
Stock-based compensation	71	—
Other non-cash items	(287)	1,532
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(265)	1,811
Inventories	(1,041)	195
Accounts payable, to affiliates, and accrued liabilities	5,176	(911)
Taxes accrued	9,022	—
Other assets/liabilities	1,936	(2,715)
Regulatory assets/liabilities	(3,137)	(1,331)
Net Cash Provided by Operating Activities	**22,984**	**16,308**
Cash Flow From Investing Activities:		
Capital expenditures	(18,448)	(15,923)
Contributions in aid of construction	214	—
Proceeds from sale of property, plant and equipment	231	—
Net Cash Used in Investing Activities	**(18,003)**	**(15,923)**
Cash Flow From Financing Activities:		
Non-current debt issuance	—	25,000
Repayments of non-current debt	(1,646)	(9,455)
Notes payable to affiliates	(9,010)	(14,033)
Capital contributions	10,000	—
Dividends paid	—	(2,000)
Other	—	(167)
Net Cash Used in Financing Activities	**(656)**	**(655)**
Net Increase (Decrease) in Cash and Cash Equivalents	**4,325**	**(270)**
Cash and Cash Equivalents, Beginning of Period	**212**	**482**
Cash and Cash Equivalents, End of Period	**$ 4,537**	**$ 212**

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

The Berkshire Gas Company
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of Shares (*)	Common Stock	Additional Paid-In Capital	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2019	**100**	**$ —**	**$ 106,095**	**$ 14,575**	**$ 120,670**
Net income	—	—	—	4,385	4,385
Common stock dividends	—	—	—	(2,000)	(2,000)
Balance at December 31, 2020	**100**	**$ —**	**$ 106,095**	**$ 16,960**	**$ 123,055**
Net income	—	—	—	4,363	4,363
Stock-based compensation	—	—	348	—	348
Capital contributions	—	—	10,000	—	10,000
Balance at December 31, 2021	**100**	**$ —**	**$ 116,443**	**$ 21,323**	**$ 137,766**

(*) Par value of share amounts is $2.50

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

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

***Background and nature of operations*:** The Berkshire Gas Company (Berkshire, the company, we, our, us), engages in natural gas transportation, distribution and sales operations in Massachusetts serving approximately 41,000 customers in its service area totaling 738 square miles as of December 31, 2021. Berkshire is regulated by the Massachusetts Department of Public Utilities (DPU) as it relates to utility service.

Berkshire is the principal operating utility of Berkshire Energy Resources (BER), a wholly-owned subsidiary of UIL Holdings Corporation (UIL Holdings). BER is a holding company whose sole business is ownership of its operating regulated gas utility. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (Avangrid), which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

***Basis of presentation*:** The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

***Significant Accounting Policies*:** We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our financial statements:

***Revenue recognition*:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

***Regulatory accounting*:** We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

***Goodwill*:** Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred, the fair value of any noncontrolling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

***Utility plant*:** We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rate for depreciation was 2.7% of average depreciable property for 2021 and 2.9% for 2020. We amortize our capitalized software cost, which is included in common plant, using the straight-line method, based on useful lives of 3 to 10 years. Depreciation expense was $8.0 million in 2021 and $7.4 million in 2020. Amortization of capitalized software was $0.9 million in 2021 and $0.8 million in 2020.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	Estimated useful life range (years)		2021		2020
(thousands)					
Gas distribution plant	8-65	$	250,804	$	224,523
Software	3-10		11,590		8,791
Land			2,305		2,305
Buildings and improvements	50-55		31,465		29,738
Other plant	25-55		8,061		27,188
Utility plant at original cost			304,225		292,545
Less accumulated depreciation			(100,334)		(97,086)
Net Utility Plant in Service			**203,891**		**195,459**
Construction work in progress			4,619		4,657
Total Utility Plant		$	**208,510**	$	**200,116**

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

Fair value measurement: 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Cash and cash equivalents: Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our balance sheets. We report changes in book overdrafts in the operating activities section of our statements of cash flows.

***Statements of cash flows*:** Supplemental disclosure of cash flow information is as follows:

		2021		2020
(Thousands)				
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	2,660	$	2,788
Income taxes (refunded) paid, net	$	5,343	$	—

Accrued liabilities for utility plant additions were $1.3 million in 2021 and $2.0 million in 2020.

***Trade receivables and unbilled revenue, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $7.2 million for 2021 and $6.1 million for 2020, and are shown net of an allowance for credit losses at December 31 of $3.2 million for 2021 and $3.2 million for 2020. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $1.0 million in 2021 and $1.6 million in 2020.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

***Debentures, bonds and bank borrowings*:** We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our balance sheets.

Gas in storage: Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our balance sheets within “Fuel and natural gas in storage.”

Materials and supplies: We also have materials and supplies inventories that we use for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on our balance sheets within “Materials and supplies.” We combine inventory items for the statement of cash flow presentation purposes.

In addition, stand-alone renewable energy credits that are generated or purchased and held for sale are recorded at the lower of cost or net realizable value and are reported on our balance sheets within “Materials and supplies.”

Government grants: We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in the period in which we incur the expenses.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them to earnings when revenue recognition criteria are met.

Accrued removal obligations**:** We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2046.

Post-employment and other employee benefits**:** We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan’s assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan’s assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain non-qualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the DPU. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes**:** AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, Berkshire settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax payable balance due to AGR at December 31 is $7.3 million for 2021, and the aggregate amount of the related party income tax receivable due from AGR is $1.8 million for 2020.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2021 and 2020.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is not more likely than not that we will realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current in our balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in “Taxes other than income taxes” and “Taxes accrued” in our financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in the statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Reclassifications: Certain amounts reported in the financial statements in previous periods have been reclassified to conform to the current year presentation.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation; (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments; and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers’ application of income-tax related guidance and simplify U. S. GAAP for: (1) franchise taxes that are partially based on income; (2) transactions with a government that result in a step up in the tax basis of goodwill; (3) separate financial statements of legal entities that are not subject to tax; and (4) enacted changes in tax laws in interim periods. We adopted the amendments effective January 1, 2021, with no material effect to our results of operations, financial position, cash flows and disclosures. We are applying the amendments on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment requirement.

(b) Improvements to lessor accounting for certain leases with variable lease payments

In July 2021, the FASB issued amendments to make targeted improvements to ASC 842 for lessor's accounting for certain leases with variable lease payments, which affect lease classification. The amendments require a lessor to classify and account for a lease with variable lease payments as an operating lease if (a) the lease would have been classified as a sales-type lease or a direct financing lease and (b) the lessor would have otherwise recognized a day-one loss. The amendments are effective for fiscal years beginning after December 15, 2021, for all entities, and interim periods within those fiscal years for public business entities, with early application permitted. We have elected to early apply the amendments effective October 1, 2021, and apply the amendments prospectively to leases that commence or are modified on or after that date. Our adoption does not materially affect our results of operations, financial position and cash flows.

(c) Accounting for revenue contracts with customers acquired in a business combination

In October 2021, the FASB issued amendments related to the accounting for revenue contracts acquired in a business combination. The amendments require an entity (acquirer) to recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606, Revenue from Contracts with Customers. At the acquisition date, an acquirer should account for the related revenue contract in accordance with ASC 606 as if it had originated the contracts. Generally, this should result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree's financial statements. The amendments also provide certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. For public business entities, the amendments are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The amendments should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted. We have elected to early apply the amendments effective October 1, 2021. Our adoption did not materially affect our results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2021, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments were effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Our prospective adoption of ASC 848 on January 1, 2022 will not materially affect our results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

In November 2021, the FASB issued amendments that apply to business entities (all entities except specified not-for-profit entities and employee benefit plans) that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance (such as a grant model within International Accounting Standards 20 Accounting for Government Grants and Disclosure of Government Assistance, or ASC Subtopic 958-605, Not-For-Profit Entities—Revenue Recognition). Government assistance can include tax credits (excluding transactions within the scope of Topic 740, Income Taxes), cash grants, grants of other assets, and project grants. Often, government assistance is provided to an entity for a particular purpose, and the entity promises to take specific actions. Transactions with a government, as used in ASC 832, Government Assistance, include assistance administered by domestic, foreign, local (city, town, county, municipal), regional (state, provincial, territorial), and national (federal) governments and entities related to those governments. The amendments require annual disclosures in notes to financial statements about transactions with a government as follows: (1) information about the nature of the transactions and the related accounting policy used to account for the transactions, (2) the line items on the balance sheet and income statement affected by the transactions, and the amounts applicable to each financial statement line item, and (3) significant terms and conditions of the transactions, including commitments and contingencies. For entities within scope the amendments are effective for annual periods beginning after December 15, 2021, with early application permitted. The amendments are to be applied either (1) prospectively to transactions within the scope of the amendments that are reflected in financial statements at the date of initial application and new transactions that are entered into after the date of initial application or (2) retrospectively to those transactions. Our adoption of the amendments on January 1, 2022 will not materially affect our disclosures.

***Use of estimates and assumptions*:** The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) earnings sharing mechanism (ESM); (10) environmental remediation liabilities; (11) pension and other postretirement employee benefits (OPEB); and (12) fair value measurements. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 78% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Rates

Utilities are entitled by Massachusetts statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

Berkshire's rates are established by the DPU. On January 18, 2019, the DPU approved new distribution rates for Berkshire. The distribution rate increase was based on an ROE of 9.70% and 54.0% equity ratio. The new tariffs provided for the implementation of a revenue decoupling mechanism and pension expense tracker and also provide that Berkshire will not file to change base distribution rates to become effective before November 1, 2021. BGC expects to file an application to amend its distribution rates in its first half of 2022. We cannot predict the outcome of this proceeding.

Based on existing tracking mechanisms in place for gas and other costs, discussions with the DPU, and precedence set by other utility companies, Berkshire believes that regulatory assets are recoverable and regulatory liabilities are fairly stated. Additionally, Berkshire has a purchased gas adjustment clause approved by the DPU which enables the reasonably incurred cost of gas purchases to be passed through to customers. This clause allows Berkshire to recover changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Gas Supply Arrangements

Berkshire satisfies its natural gas supply requirements through purchases from various producer/suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. Berkshire operates diverse portfolios of gas supply, firm transportation, gas storage and peaking resources. Actual reasonable gas costs incurred by Berkshire are passed through to customers through state regulated purchased gas adjustment mechanisms subject to regulatory review.

Berkshire purchases the majority of the natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. Berkshire diversifies its sources of supply by amount purchased and by location while primarily acquiring gas in the Appalachia region.

Berkshire acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline interconnects with Berkshire's distribution system upstream of the city gates. The prices and terms and conditions of the firm transportation capacity long-term contracts are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

Berkshire acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York and West Virginia.

Winter peaking resources are primarily attached to the local distribution system and are owned by Berkshire. Berkshire owns or has rights to the natural gas stored in its Liquefied Natural Gas (LNG) facility that is directly attached to its distribution system.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $20.0 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of regulatory assets and regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and non-current regulatory assets at December 31, 2021 and 2020 consisted of:

December 31,		2021		2020
(Thousands)				
Current				
Debt premium	$	—	$	189
Deferred purchased gas		9,486		6,586
Energy efficiency programs		1,820		1,137
Pension and other postretirement benefits		—		1,043
Recoverable bad debt		1,196		—
Revenue decoupling mechanism		2,385		1,317
Other		1,029		705
Total current regulatory assets	**$**	**15,916**	**$**	**10,977**
Non-current				
Environmental remediation costs	$	5,104	$	5,501
Debt premium		—		2
Recoverable bad debt		—		1,012
Pension and other postretirement benefits		16,942		21,955
Unfunded future income taxes		482		482
Other		329		1,167
Total non-current regulatory assets	**$**	**22,857**	**$**	**30,119**

Debt premium represents the regulatory asset recorded to offset the fair value adjustment to the regulatory component of the non-current debt of UIL at the acquisition date. This amount is being amortized to interest expense over the remaining term of the related outstanding debt instruments.

Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.

Energy efficiency programs represent all expenditures for a twelve month period as contained in the Company's Energy Efficiency budgets as defined and approved by the Department, including, but not limited to, Energy Efficiency Program Costs, Reconciliation Adjustments, Energy Efficiency Lost Margins, Energy Efficiency Performance Incentives, Working Capital and Interest. At the end of each twelve-month period, the Company will include the Reconciliation Adjustment associated with over- or under-recoveries of allowable EE Expenditures billed over the prior twelve-month period. Pursuant to the to the Department's approved Energy Efficiency Guidelines, estimated lost margins and performance incentives approved in the Company's Plan may be collected during the term of the Plan and shall be reconciled at the end of the term in the Company's Term Report.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base.

Rate adjustment mechanism represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but this also includes property taxes and REV costs and fees not covered in other recovery mechanisms

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes items such as pension cost deferral and rate case cost.

Current and non-current regulatory liabilities at December 31, 2021 and 2020 consisted of:

December 31,		2021		2020
(Thousands)				
Current				
Tax Act – remeasurement	$	—	$	1,152
Other		198		—
Total current regulatory liabilities	**$**	**198**	**$**	**1,152**
Non-current				
Asset removal obligations	$	38,117	$	37,391
Pension and other postretirement benefits		1,082		1,103
Tax Act – remeasurement		12,709		12,395
Non-firm margin sharing credits		—		84
Other		—		417
Total non-current regulatory liabilities	**$**	**51,908**	**$**	**51,390**

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

Berkshire derives revenue primarily from tariff-based sales of natural gas delivered to customers. For such revenues, Berkshire recognize revenues in an amount derived from the commodities delivered to customers. Another major source of revenue is wholesale sales of natural gas.

Tariff-based sales are subject to DPU approval, which determines prices and other terms of service through the ratemaking process. Certain customers have the option to obtain the natural gas directly from Berkshire or from another supplier. For customers that receive their natural gas from another supplier, Berkshire acts as an agent and delivers the natural gas for that supplier. Revenue in those cases is only for providing the service of delivery of the natural gas. Berkshire calculates revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as Berkshire delivers or sells the natural gas. Berkshire records revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered, which corresponds to the amount that Berkshire has a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. Berkshire does not adjust the promised consideration for the effects of a significant financing component if it expects, at contract inception, that the time between the delivery of promised goods or service and customer payment will be one year or less. Berkshire does not have any material significant payment terms because it receives payment at or shortly after the point of sale.

Berkshire also records revenue from an Alternative Revenue Program (ARP), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. Berkshire ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

Berkshire also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. They classify such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, or ARPs.

Revenues disaggregated by major source for the years ended December 31, 2021 and 2020 are as follows:

Years Ended December 31,	2021	2020
(Thousands)		
Regulated operations – natural gas	$ 82,557	$ 73,542
Other (a)	12	16
Revenue from contracts with customers	**82,569**	**73,558**
Leasing revenue	956	1,117
Alternative revenue programs	1,918	2,466
Other revenue	22	—
Total operating revenues	**$ 85,465**	**$ 77,141**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting Berkshire.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of our cash flows and the rates of return market participants would require in order to invest their capital in Berkshire. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

For 2021, we utilized a qualitative assessment and for 2020, we utilized a quantitative assessment. We had no impairment of goodwill in 2021 and 2020 as a result of our impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2021 or 2020 that required us to update the assessment.

The carrying amount of goodwill, which resulted from the purchase of Berkshire by UIL Holdings in 2010, was $51.9 million at both December 31, 2021 and 2020, with no accumulated impairment losses and no changes during 2021 and 2020

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,		2021		2020
(Thousands)				
Current				
Federal	$	2,371	$	(393)
State		607		(710)
Current taxes charged to (benefit) expense		**2,978**		**(1,103)**
Deferred				
Federal		(1,841)		1,060
State		(258)		1,246
Deferred taxes charged to expense (benefit)		**(2,099)**		**2,306**
Total Income Tax Expense	**$**	**879**	**$**	**1,203**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2021 and 2020, respectively, consisted of:

Years Ended December 31,		2021		2020
(Thousands)				
Tax expense at federal statutory rate	$	1,101	$	1,173
Excess ADIT amortization		(838)		(838)
State tax expense, net of federal benefit		275		424
Other, net		341		444
Total Income Tax Expense	**$**	**879**	**$**	**1,203**

Income tax expense for the year ended December 31, 2021 was $0.2 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess ADIT amortization, partially offset by state tax expense. This resulted in an effective tax rate of 16.8%. Income tax expense for the year ended December 31, 2020 was $0.03 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes. This resulted in an effective tax rate of 21.5%.

Deferred tax assets and liabilities as of December 31, 2021 and 2020 consisted of:

December 31,		2021		2020
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related		30,230	$	30,918
Deferred gas and other deferred charges	$	1,884		1,229
2017 Tax Act measurement		(3,701)		(3,701)
Federal and state net operating loss		(1,212)		(953)
Pension and other postretirement benefits		43		547
Other		(441)		24
Total Non-current Deferred Income Tax Liabilities		**26,803**		**28,064**
Deferred tax assets		5,354		4,654
Deferred tax liabilities		32,157		32,718
Net Accumulated Deferred Income Tax Liabilities		**26,803**	**$**	**28,064**

Berkshire has gross federal net operating losses of $1.2 million for the year ended December 31, 2021. Berkshire had gross federal net operating losses of $1.0 million for the year ended December 31, 2020.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2021 and December 31, 2020.

Note 7. Long-term Debt

Long-term debt as of December 31, 2021 and 2020 consisted of:

As of December 31,		**2021**		**2020**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured notes	2029-2050	$ 60,000	3.68%-5.33%	$ 61,454	3.68%-7.80%
Unamortized debt issuance cost and discount		(453)		(310)	
Total Debt		**59,547**		**61,144**	
Less: debt due within one year, included in current liabilities		—		1,646	
Total Non-current Debt		**$ 59,547**		**$ 59,498**	

We have no long-term debt, including sinking fund obligations, due during the next five years.

We have no financial debt covenant requirements related to our long-term debt at December 31, 2021 and 2020.

Note 8. Bank Loans and Other Borrowings

Berkshire had no notes payable as of December 31, 2021 and $9.1 million of notes payable outstanding as of December 31, 2020. Berkshire funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility), and a bank provided credit facility to which Berkshire is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. Berkshire has a lending/borrowing limit of $15 million under this agreement. Berkshire had no debt outstanding under this agreement as of December 31, 2021 and $7.5 million as of December 31, 2020.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $50 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. Berkshire had no debt outstanding under this agreement as of December 31, 2021 and $1.6 million outstanding as of December 31, 2020.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut

Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026.

Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points Berkshire had not borrowed under this agreement as of both December 31, 2021 and 2020.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.52 to 1.00 at December 31, 2021. We are not in default as of December 31, 2021.

Note 9. Leases

We have operating leases for land rights. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 14 years, some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

For the Years Ended December 31,	**2021**	**2020**
(Thousands)		
Lease cost		
Operating lease cost	$ 4	$ —
Short-term lease cost	64	—
Total lease cost	**$ 68**	**$ —**

Balance sheet and other information for the years ended December 31, 2021 and 2020 was as follows:

As of December 31,	2021	2020
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 141	$ —
Operating lease liabilities, current	6	—
Operating lease liabilities, long-term	133	—
Total operating lease liabilities	**$ 139**	**$ —**
Weighted-average Remaining Lease Term (years):		
Operating leases	13.50	—
Weighted-average Discount Rate:		
Operating leases	2.50 %	— %

Supplemental cash flows information related to leases was as follows:

For the Years Ended December 31,	2021	2020
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 6	$ —

As of December 31, 2021, maturities of lease liabilities were as follows:

	Operating Leases
(Thousands)	
Years ending December 31,	
2022	$ 6
2023	7
2024	7
2025	7
2026	8
Thereafter	121
Total lease payments	**156**
Less: imputed interest	(17)
Total	**$ 139**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of natural gas service.

Manufactured gas plants

We own or have previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. We have or had an ownership interest in one of such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2021 and no amount of loss, if any, can be reasonably estimated at this time. In the past, we have received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

We own property on Mill Street in Greenfield, Massachusetts, a former MGP site. Management estimates that expenses associated with the remaining remedial activities, as well as the required ongoing monitoring and reporting to the Massachusetts Department of Environmental Protection will likely amount to approximately $0.5 million and has recorded a liability and offsetting regulatory asset for such expenses as of December 31, 2021. Historically, we have received approval from the DPU for recovery of environmental expenses in its customer rates.

We formerly owned a site on East Street (the East Street Site) in Pittsfield, Massachusetts, a former MGP site. The East Street Site is part of a larger site known as the GE–Pittsfield/ Housatonic River Site. We sold the East Street Site to the General Electric Company (GE) in the 1970s and was named a potentially responsible party for the site by the EPA in 1990.

In December 2002, we reached a settlement with GE which provides, among other things, a framework for us and GE to allocate various monitoring and remediation costs at the East Street Site. As of December 31, 2021, we have accrued approximately $3.5 million and established a regulatory asset for these and future costs incurred by GE in responding to releases of hazardous substances at the East Street Site. Historically, we have received approval from the DPU for recovery of remediation expenses in its customer rates.

Our environmental liabilities are recorded on an undiscounted basis and are expected to be paid through the year 2046.

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $70 million as of December 31, 2021 and $77 million as of December 31, 2020. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case.

The financial instruments measured at fair value as of December 31, 2021 and 2020 consisted of:

Description	Level 1	Level 2	Level 3	Total
(Thousands)				
2021				
Assets				
Non-current investments	$ 2,179	$ —	$ —	$ 2,179
Total	**$ 2,179**	**$ —**	**$ —**	**$ 2,179**
2020				
Assets				
Non-current investments	$ 89	$ —	$ —	$ 89
Total	**$ 89**	**$ —**	**$ —**	**$ 89**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2021. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

Note 12. Post-retirement and Similar Obligations

We have multiple qualified pension plans covering eligible union and management employees and retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. The qualified pension plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates.

Berkshire non-union employees are eligible to participate in UIL Holdings Corporation 401(k) Employee Stock Ownership Plan, and union employees are eligible to participate in the Berkshire Gas Company Union 401(k) Plan. Employees may defer a portion of their compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expense totaled approximately $0.7 million in 2021 and $0.6 million in 2020.

We also have plans providing other postretirement benefits for eligible employees and retirees. The plans were closed to newly-hired Berkshire union employees by end of March 2011. These benefits consist primarily of health care, prescription drug and life insurance benefits for retired employees and their dependents. For Medicare eligible non-union retirees, we provide a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in other non-current liabilities on our balance sheets, was $1.4 million and $1.5 million at December 31, 2021 and 2020, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 59,395	$ 55,929	$ 2,361	$ 3,050
Service cost	947	949	49	39
Interest cost	1,487	1,745	45	93
Curtailments/settlements	(1,306)	—	—	—
Actuarial (gain) loss	(2,763)	3,326	(374)	(679)
Benefits paid	(3,694)	(2,554)	(134)	(142)
Benefit obligation at December 31	**$ 54,066**	**$ 59,395**	**$ 1,947**	**$ 2,361**
Change in plan assets				
Fair value of plan assets at January 1	**$ 41,902**	**$ 37,256**	**$ —**	**$ —**
Actual return on plan assets	3,399	5,335	—	—
Employer contributions	240	1,865	134	142
Curtailments/settlements	(1,306)	—	—	—
Benefits paid	(3,694)	(2,554)	(134)	(142)
Fair value of plan assets at December 31	**$ 40,541**	**$ 41,902**	**$ —**	**$ —**
Funded status	**$ (13,525)**	**$ (17,493)**	**$ (1,947)**	**$ (2,361)**

During 2021, the pension benefit obligation had an actuarial gain of $2.8 million, primarily due to a $2.8 million gain from increases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

During 2020, the pension benefit obligation had an actuarial loss of $3.3 million, primarily due to a $4.7 million loss from decreases in discount rates. The postretirement benefit obligation had an actuarial gain of $0.7 million.

Amounts recognized in the balance sheet as of December 31, 2021 and 2020 consisted of:

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Other current liabilities	$ —	$ —	$ (142)	$ —
Pension and other postretirement benefits	(13,525)	(17,493)	(1,805)	(2,361)
Total	**$ (13,525)**	**$ (17,493)**	**$ (1,947)**	**$ (2,361)**

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

December 31,	Pension Benefits 2021	2020	Postretirement Benefits 2021	2020
(Thousands)				
Net loss (gain)	$ 7,198	$ 11,434	$ (1,082)	$ (787)
Prior service cost	$ 1	$ 1	$ —	$ —

Our accumulated benefit obligation for all qualified defined benefit pension plans was $50.7 million at December 31, 2021 and $54.5 million at December 31, 2020.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all of our qualified plans as of both December 31, 2021 and 2020. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets of our plans as of December 31, 2021 and 2020.

December 31,	2021	2020
(Thousands)		
Projected benefit obligation	$ 54,066	$ 59,395
Accumulated benefit obligation	$ 50,706	$ 54,534
Fair value of plan assets	$ 40,541	$ 41,902

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2021 and 2020.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	2020	Postretirement Benefits 2021	2020
(Thousands)				
Net periodic benefit cost				
Service cost	$ 947	$ 949	$ 49	$ 39
Interest cost	1,487	1,745	45	93
Expected return on plan assets	(2,903)	(2,663)	—	—
Amortization of actuarial loss (gain)	880	937	(79)	(12)
Settlement charge	98	—	—	—
Net periodic benefit cost	**$ 509**	**$ 968**	**$ 15**	**$ 120**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ (3,260)	$ 654	$ (373)	$ (680)
Amortization of actuarial (loss) gain	(880)	(937)	79	12
Settlement charge	(98)	—	—	—
Total Other Changes	**(4,238)**	**(283)**	**(294)**	**(668)**
Total Recognized	**$ (3,729)**	**$ 685**	**$ (279)**	**$ (548)**

We include the service component of net periodic benefit cost in other operating expenses and the non-service component in other income and deductions. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
Discount rate	2.96%	2.56%	2.61%	2.00%
Rate of compensation increase	3.50% / 2.50%	3.08%	N/A	N/A
Interest crediting rate	2.00% / N/A	2.84%	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
Discount rate	2.56%	3.19%	2.00%	3.19%
Expected long-term return on plan assets	7.00%	7.21%	N/A	N/A
Rate of compensation increase	3.50% / 2.50%	3.50%	N/A	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred as required by the DPU.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	**2021**	**2020**
Health care cost trend rate (pre 65/post 65)	6.25% / 7.00%	6.50%/7.25%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50% / 4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029/2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $0.5 million and $0.1 million, respectively, to our pension and other postretirement benefit plans during 2022.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2022	$ 2,803	$ 142	$ —
2023	$ 2,794	$ 121	$ —
2024	$ 2,832	$ 141	$ —
2025	$ 2,903	$ 164	$ —
2026	$ 2,986	$ 174	$ —
2027-2031	$ 15,127	$ 696	$ —

Plan assets: Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

Asset Category		Total		Fair Value Measurements at December 31, Using Level 1		Level 2		Level 3
(Thousands)								
2021								
Cash and cash equivalents	$	944	$	181	$	763	$	—
U.S. government securities		2,224		2,224		—		—
Common stocks		1,845		1,845		—		—
Registered investment companies		3,828		3,828		—		—
Corporate bonds		10,665		—		10,665		—
Preferred stocks		12		12		—		—
Common collective trusts		13,641		—		13,641		—
Other investments, principally annuity and fixed income		262		—		262		—
	$	**33,421**	**$**	**8,090**	**$**	**25,331**	**$**	**—**
Other investments measured at net asset value		7,120						
Total	**$**	**40,541**						

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

Asset Category		Total		Fair Value Measurements at December 31, Using Level 1		Level 2		Level 3
(Thousands)								
2020								
Cash and cash equivalents	$	934	$	1	$	933	$	—
U.S. government securities		2,420		2,419		1		—
Common stocks		1,425		1,425		—		
Registered investment companies		4,118		4,118		—		—
Corporate bonds		9,696		—		9,696		—
Preferred stocks		13		13		—		—
Common collective trusts		15,891		—		15,891		
Other investments, principally annuity and fixed income		58		87		(29)		—
	$	**34,555**	**$**	**8,063**	**$**	**26,492**	**$**	**—**
Other investments measured at net asset value		7,347						
Total	**$**	**41,902**						

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.

- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2021 and 2020.

Note 13. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2021 and 2020, consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Allowance for funds used during construction	$ 79	$ —
Carrying costs on regulatory assets	369	—
Interest and dividend income	90	194
Miscellaneous	1	107
Total other income	**$ 539**	**$ 301**
Pension non-service components	(962)	(1,142)
Miscellaneous	(1,240)	(245)
Total other deductions	**$ (2,202)**	**$ (1,387)**

Note 14. Related Party Transactions

Certain Networks subsidiaries borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including Berkshire. For Berkshire the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including Berkshire, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating services provided to Berkshire by AGR and its affiliates was approximately $4.3 million and $3.1 million for the years ended December 31, 2021 and 2020, respectively

The balance in accounts payable to affiliates of $0.8 million at December 31, 2021 is mostly payable to UIL Holdings and Avangrid Service Company. The balance in accounts payable to affiliates of $0.9 million at December 31, 2020 is payable to various companies. The balance in accounts receivable from affiliates is $0.03 million at December 31, 2021; the balance of $0.6 million at December 31, 2020 is mostly from UIL Holdings.

Note 15. Subsequent Events

The company has performed a review of subsequent events through March 31, 2022, which is the date these financial statements were available to be issued.

On May 21, 2021, the Pipeline Safety Division (Division) of the DPU and Berkshire entered into a Work Plan Agreement (WPA) regarding items of noncompliance with state and federal pipeline safety regulations and state statutes. Per the WPA, this noncompliance authorizes the DPU to assess annual civil penalties as specified in G.L. c. 164, § 105A, as amended, for each compliance item. In March 2022 , Berkshire was assessed a penalty of $0.75 million, which has been reflected in the financial statements in other deductions on Berkshire's statements of income as of December 31, 2021.

Connecticut Natural Gas Corporation
Financial Statements
As of and for the Years Ended December 31, 2021 and 2020

Connecticut Natural Gas Corporation

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
Connecticut Natural Gas Corporation:

Opinion

We have audited the financial statements of Connecticut Natural Gas Corporation (the Company), which comprise the balance sheets as of December 31, 2021 and 2020, and the related statements of income, comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

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

Responsibilities of Management for the Financial Statements

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

KPMG LLP

New York, New York
March 31, 2022

Connecticut Natural Gas Corporation
Statements of Income

Years Ended December 31,		2021		2020
(Thousands)				
Operating Revenues	$	**419,074**	$	**368,550**
Operating Expenses				
Natural gas purchased		185,342		143,289
Operations and maintenance		102,744		102,112
Depreciation and amortization		45,837		43,067
Taxes other than income taxes, net		32,676		29,063
Total Operating Expenses		**366,599**		**317,531**
Operating Income		**52,475**		**51,019**
Other income		2,106		1,151
Other deductions		(3,558)		(4,433)
Interest expense, net of capitalization		(9,817)		(9,255)
Income Before Income Tax		**41,206**		**38,482**
Income tax expense		8,343		11,030
Net Income	$	**32,863**	$	**27,452**

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

Connecticut Natural Gas Corporation
Statements of Comprehensive Income

Years Ended December 31,		2021		2020
(Thousands)				
Net Income	$	**32,863**	$	**27,452**
Other Comprehensive Income (Loss), Net of Tax				
Amortization of pension cost for nonqualified plans, net of income tax of $122 for 2020 and $47 for 2021		(128)		(332)
Total Other Comprehensive Income (Loss), Net of Tax		**(128)**		**(332)**
Comprehensive Income	$	**32,735**	$	**27,120**

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

Connecticut Natural Gas Corporation
Balance Sheets

As of December 31,		2021		2020
(Thousands)				
Assets				
Current Assets				
Cash and cash equivalents	$	—	$	831
Accounts receivable and unbilled revenues, net		107,019		88,797
Accounts receivable from affiliates		706		2,419
Notes receivable from affiliates		—		5,050
Gas in storage		30,118		23,393
Materials and supplies		4,653		1,574
Income tax receivable		—		2,707
Other current assets		2,179		1,130
Regulatory assets		51,867		29,845
Total Current Assets		**196,542**		**155,746**
Utility plant, at original cost		1,142,558		1,083,498
Less accumulated depreciation		(374,307)		(354,919)
Net Utility Plant in Service		**768,251**		**728,579**
Construction work in progress		19,823		26,126
Total Utility Plant		**788,074**		**754,705**
Operating lease right-of-use assets		542		475
Other property and investments		833		960
Regulatory and Other Assets				
Regulatory assets		84,532		112,275
Goodwill		79,341		79,341
Other		128		203
Total Regulatory and Other Assets		**164,001**		**191,819**
Total Assets	**$**	**1,149,992**	**$**	**1,103,705**

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

Connecticut Natural Gas Corporation
Balance Sheets

As of December 31,		2021		2020
(Thousands, except share information)				
Liabilities				
Current Liabilities				
Notes payable to affiliates	$	8,700	$	—
Accounts payable and accrued liabilities		63,248		62,658
Accounts payable to affiliates		19,338		6,242
Interest accrued		2,501		2,597
Taxes accrued		19,397		5,534
Operating lease liabilities		607		419
Regulatory liabilities		4,844		10,195
Other		17,664		4,885
Total Current Liabilities		**136,299**		**92,530**
Regulatory and Other Liabilities				
Regulatory liabilities		276,003		252,514
Other Non-current Liabilities				
Deferred income taxes		38,702		35,459
Pension and other postretirement		71,389		97,749
Operating lease liabilities		100		253
Asset retirement obligation		6,398		6,499
Other		2,429		3,101
Total Regulatory and Other Liabilities		**395,021**		**395,575**
Non-current debt		188,939		188,971
Total Liabilities		**720,259**		**677,076**
Commitments and Contingencies				
Preferred Stock		**340**		**340**
Common Stock Equity				
Common stock ($3.125 par value, 20,000,000 shares authorized and 10,634,436 shares outstanding at December 31, 2021 and 2020)		33,233		33,233
Additional paid-in capital		366,698		386,302
Retained earnings		29,922		7,086
Accumulated other comprehensive loss		(460)		(332)
Total Common Stock Equity		**429,393**		**426,289**
Total Liabilities and Equity	**$**	**1,149,992**	**$**	**1,103,705**

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

Connecticut Natural Gas Corporation
Statements of Cash Flows

Years Ended December 31,	2021	2020
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 32,863**	**$ 27,452**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	45,837	43,067
Regulatory assets/liabilities amortization	12,463	4,342
Regulatory assets/liabilities carrying cost	39	339
Amortization of debt issuance costs	48	100
Deferred taxes	2,747	14,839
Pension cost	879	8,512
Stock-based compensation	94	—
Accretion expenses	333	—
Other non-cash items	(101)	2,946
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(16,509)	3,173
Inventories	(9,804)	3,640
Accounts payable, to affiliates, and accrued liabilities	19,534	(9,388)
Taxes accrued	16,570	1,758
Other assets/liabilities	7,039	(14,066)
Regulatory assets/liabilities	(29,113)	(18,457)
Net Cash Provided by Operating Activities	**82,919**	**68,257**
Cash Flow from Investing Activities:		
Capital expenditures	(68,287)	(52,986)
Contributions in aid of construction	792	—
Proceeds from sale of utility plant	22	—
Notes receivable from affiliates	5,050	7,250
Net Cash Used in Investing Activities	**(62,423)**	**(45,736)**
Cash Flow from Financing Activities:		
Non-current debt issuance	—	30,000
Return of capital	(40,000)	(12,000)
Notes payable to affiliates	8,700	(58)
Capital contribution	20,000	40,000
Dividends paid	(10,027)	(80,027)
Other	—	(181)
Net Cash Used in Financing Activities	**(21,327)**	**(22,266)**
Net (Decrease) Increase in Cash and Cash Equivalents	**(831)**	**255**
Cash and Cash Equivalents, Beginning of Period	**831**	**576**
Cash and Cash Equivalents, End of Period	**$ —**	**$ 831**

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

Connecticut Natural Gas Corporation
Statements of Changes in Equity

(Thousands, except per share amounts)	Number of shares (*)	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity
Balances, December 31, 2019	**10,634,436**	**$ 33,233**	**$ 358,302**	**$ 59,661**	**$ —**	**$ 451,196**
Net income	—	—	—	27,452	—	27,452
Other comprehensive income, net of tax	—	—	—	—	(332)	(332)
Comprehensive income						27,120
Common stock dividends	—	—	—	(80,000)	—	(80,000)
Preferred stock dividends	—	—	—	(27)	—	(27)
Return of capital	—	—	(12,000)	—	—	(12,000)
Capital contribution	—	—	40,000	—	—	40,000
Balances, December 31, 2020	**10,634,436**	**33,233**	**386,302**	**7,086**	**(332)**	**426,289**
Net income	—	—	—	32,863	—	32,863
Other comprehensive income, net of tax	—	—	—	—	(128)	(128)
Comprehensive income						32,735
Stock-based compensation	—	—	396	—	—	396
Common stock dividends	—	—	—	(10,000)	—	(10,000)
Preferred stock dividends	—	—	—	(27)	—	(27)
Capital contribution	—	—	20,000	—	—	20,000
Return of capital	—	—	(40,000)	—	—	(40,000)
Balances, December 31, 2021	**10,634,436**	**$ 33,233**	**$ 366,698**	**$ 29,922**	**$ (460)**	**$ 429,393**

(*) Par value of share amounts is $3.125

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

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

Background and nature of operations: Connecticut Natural Gas Corporation (CNG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 184,490 customers as of December 31, 2021, in service areas totaling approximately 724 square miles. CNG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

CNG is the principal operating utility of CTG Resources, Inc. (CTG), a wholly owned subsidiary of UIL Holdings Corporation (UIL Holdings). CTG is a holding company whose sole business is ownership of its operating regulated gas utility. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (Avangrid), which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

Basis of presentation: The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

Significant Accounting Policies: We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our financial statements:

Revenue recognition**:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

Regulatory accounting: We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

Goodwill**:** Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred, the fair value of any noncontrolling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

Utility plant: We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 3.9% and 4.0% of average depreciable property for 2021 and 2020, respectively. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 15 years. Depreciation expense was $42.8 million in 2021 and $39.9 million in 2020. Amortization of capitalized software was $3.0 million in 2021 and $3.2 million in 2020.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	Estimated useful life range (years)	2021	2020
(Thousands)			
Gas distribution plant	5-75	$ 994,356	$ 909,160
Software	3-10	41,984	34,575
Land	N/A	1,618	1,618
Building and improvements	35-50	36,428	35,298
Other plant	45-90	68,172	102,847
Total Utility Plant in Service		**1,142,558**	**1,083,498**
Total accumulated depreciation		(374,307)	(354,919)
Total Net Utility Plant in Service		**768,251**	**728,579**
Construction work in progress		19,823	26,126
Total Utility Plant		**$ 788,074**	**$ 754,705**

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

Fair value measurement: 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Cash and cash equivalents: Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our balance sheets. We report changes in book overdrafts in the operating activities section of the statements of cash flows.

Statements of cash flows: Supplemental disclosure of cash flow information is as follows:

(Thousands)		2021		2020
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	8,697	$	8,270
Income taxes paid, net	$	7,211	$	5,235

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $0.3 million in 2021 and $0.1 million in 2020. Accrued liabilities for utility plant additions were $1.3 million in 2021 and $7.9 million in 2020.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers but not yet billed. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $31.3 million for 2021 and $27.2 million for 2020, and are shown net of an allowance for credit losses at December 31 of $6.8 million for 2021 and $2.3 million for 2020. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $8.6 million in 2021 and $7.7 million in 2020.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

Debentures, bonds and bank borrowings: We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our balance sheets.

Gas in storage: Natural gas in storage is stored in both self-owned and third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value.

Materials and supplies: Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within “Materials and supplies.” We combine inventory items for the statement of cash flows presentation purposes.

Government grants**:** We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in which we incur the expenses.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them into earnings when revenue recognition criteria are met.

Asset retirement obligations**:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas main. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity’s legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2021 and 2020.

Years Ended December 31,		**2021**		**2020**
(Thousands)				
ARO, beginning of year	$	6,499	$	6,576
Liabilities settled during the year		(434)		(422)
Accretion expenses		333		345
ARO, end of year	**$**	**6,398**	**$**	**6,499**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including the removal of property upon termination of an easement, right-of-way or franchise.

Accrued removal obligations: We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

***Environmental remediation liability*:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over the average remaining service period or 10 years. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes: AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, CNG settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax payable balance due to AGR at December 31, 2021 was $11.2 million. The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2020 was $2.7 million.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current on our balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in "Taxes other than income taxes" and "Taxes accrued" in our financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other income” and “Other deductions” in our statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the income tax components of the financial statements.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Reclassifications: Certain amounts reported in the financial statements in previous periods have been reclassified to conform to the current year presentation.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation; (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments; and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U.S. GAAP for: (1) franchise taxes that are partially based on income; (2) transactions with a government that result in a step up in the tax basis of goodwill; (3) separate financial statements of legal entities that are not subject to tax; and (4) enacted changes in tax laws in interim periods. We adopted the amendments effective January 1, 2021, with no material effect to our results of operations, financial position, cash flows and disclosures. We are applying the amendments on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment requirement.

(b) Improvements to lessor accounting for certain leases with variable lease payments

In July 2021, the FASB issued amendments to make targeted improvements to ASC 842 for lessor's accounting for certain leases with variable lease payments, which affect lease classification. The amendments require a lessor to classify and account for a lease with variable lease payments as an operating lease if (a) the lease would have been classified as a sales-type lease or a direct financing lease and (b) the lessor would have otherwise recognized a day-one loss. The amendments are effective for fiscal years beginning after December 15, 2021, for all entities, and interim periods within those fiscal years for public business entities, with early application permitted. We have elected to early apply the amendments effective October 1, 2021, and apply the amendments prospectively to leases that commence or are modified on or after that date. Our adoption does not materially affect our results of operations, financial position and cash flows.

(c) Accounting for revenue contracts with customers acquired in a business combination

In October 2021, the FASB issued amendments related to the accounting for revenue contracts acquired in a business combination. The amendments require an entity (acquirer) to recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606, Revenue from Contracts with Customers. At the acquisition date, an acquirer should account for the related revenue contract in accordance with ASC 606 as if it had originated the contracts. Generally, this should result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree's financial statements. The amendments also provide certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. For public business entities, the amendments are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The amendments should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted. We have elected to early apply the amendments effective October 1, 2021. Our adoption did not materially affect our results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2021, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments were effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Our prospective adoption of ASC 848 on January 1, 2022 will not materially affect our results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

In November 2021, the FASB issued amendments that apply to business entities (all entities except specified not-for-profit entities and employee benefit plans) that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance (such as a grant model within International Accounting Standards 20 Accounting for Government Grants and Disclosure of Government Assistance, or ASC Subtopic 958-605, Not-For-Profit Entities—Revenue Recognition). Government assistance can include tax credits (excluding transactions within the scope of Topic 740, Income Taxes), cash grants, grants of other assets, and project grants. Often, government assistance is provided to an entity for a particular purpose, and the entity promises to take specific actions. Transactions with a government, as used in ASC 832, Government Assistance, include assistance administered by domestic, foreign, local (city, town, county, municipal), regional (state, provincial, territorial), and national (federal) governments and entities related to those governments. The amendments require annual disclosures in notes to financial statements about transactions with a government as follows: (1) information about the nature of the transactions and the related accounting policy used to account for the transactions, (2) the line items on the balance sheet and income statement affected by the transactions, and the amounts applicable to each financial statement line item, and (3) significant terms and conditions of the transactions, including commitments and contingencies. For entities within scope the amendments are effective for annual periods beginning after December 15, 2021, with early application permitted. The amendments are to be applied either (1) prospectively to transactions within the scope of the amendments that are reflected in financial statements at the date of initial application and new transactions that are entered into after the date of initial application or (2) retrospectively to those transactions. Our adoption of the amendments on January 1, 2022 will not materially affect our disclosures.

Use of estimates and assumptions**:** The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) environmental remediation liabilities; (10) AROs; (11) pension and other postretirement employee benefits (OPEB); (12) investments in equity instruments; and (13) earnings sharing mechanisms. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 77% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Rates

Utilities are entitled by Connecticut statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

In December, 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with rate increases of $9.9 million, $4.6 million and $5.2 million in 2019, 2020 and 2021, respectively. The new tariffs, which are based on an ROE of 9.30% and an equity ratio of

54% in 2019, 54.50% in 2020, and 55% in 2021, continued, among other things, two separate ratemaking mechanisms that reconcile actual revenue requirements related to CNG's cast iron and bare steel replacement program and system expansion as well as a revenue decoupling mechanism and CNG's earnings sharing mechanism whereby CNG is required to return to customers 50% of any earnings over the allowed ROE in a calendar year and tariff increases.

Additionally, CNG has a purchased gas adjustment clause, approved by PURA, which enables reasonably incurred cost of gas purchases to be passed through to customers. This clause allows CNG to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Gas Supply Arrangements

CNG satisfies its natural gas supply requirements through purchases from various producer/ suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. CNG operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by CNG are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

CNG purchases the majority of our natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. CNG diversifies its sources of supply by amount purchased and location and primarily acquires gas at various locations in the US Gulf of Mexico region, in the Appalachia region and in Canada.

CNG acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline, Algonquin Gas Transmission and Iroquois Gas Transmission interconnect with CNG's distribution system and the other pipelines provide indirect services upstream of the city gates. The prices and terms and conditions of the long-term contracts for firm transportation capacity are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

CNG acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York, West Virginia and Michigan.

CNG owns 100% of the Liquefied Natural Gas (LNG) stored in an LNG facility which is directly attached to its distribution system. CNG uses the LNG capacity as a winter peaking resource.

Minimum Equity Requirements for Regulated Subsidiaries

Pursuant to an agreement with PURA, CNG is restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, CNG is prohibited from paying dividends to its parent if the utility's credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility's credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future regulated rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $76.7 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and non-current regulatory assets at December 31, 2021 and 2020 consisted of:

As of December 31, (Thousands)	2021	2020
Current		
Pension and other postretirement benefit plan	$ —	$ 5,395
Hardship programs	2,914	3,075
Deferred purchased gas	22,646	11,973
Revenue decoupling mechanism	20,008	5,170
Other	6,299	4,232
Total current regulatory assets	**51,867**	**29,845**
Non-current		
Pension and other postretirement benefit plan	77,219	102,827
Unfunded future income taxes	4,266	3,958
Revenue decoupling mechanism	—	3,452
Other	3,047	2,038
Total non-current regulatory assets	**$ 84,532**	**$ 112,275**

Pension and other postretirement represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Hardship programs represent customer accounts deferred for recovery to the extent they exceed the amount in rates.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Deferred purchased gas represents the difference between actual gas costs and gas costs collected in rates. Balances at the end of the rate year are normally recorded/returned in the following year.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Other includes various items subject to reconciliation such as System Expansion Reconciliation and Environmental Defense Fund legal fees.

Current and non-current regulatory liabilities at December 31, 2021 and 2020 consisted of:

As of December 31,	**2021**	**2020**
(Thousands)		
Current		
Rate credits	$ 1,250	$ 1,250
Tax reform	3,560	3,560
Non-firm margin sharing credits	—	2,398
Other	34	2,987
Total current regulatory liabilities	**4,844**	**10,195**
Non-current		
Pension and other postretirement benefit plan	4,783	5,681
Asset removal costs	230,235	213,364
Asset retirement obligation	10,327	10,266
Rate credits	6,250	7,500
Tax reform	10,015	10,250
Non-firm margin sharing credits	7,901	4,796
Other	6,492	657
Total non-current regulatory liabilities	**$ 276,003**	**$ 252,514**

Accrued removal obligations represent the differences between asset removal costs incurred and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Asset retirement obligation represents the fair value of the liability for an asset retirement which we are legally committed to remove.

Rate credits resulted from the acquisition of UIL by Iberdrola. This is being used to moderate increases in rates.

Tax reform represents the impact from re-measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases.

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects.

Other includes various items subject to reconciliation such as Geographic Information System Data Conversion expense deferral.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

CNG derives its revenue primarily from tariff-based sales of natural gas delivered to customers. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Another major source of revenue is wholesale sales of natural gas.

Tariff-based sales are subject to PURA approval, which determines prices and other terms of service through the ratemaking process. Certain customers have the option to obtain the natural gas directly from CNG or from another supplier. For customers that receive their natural gas from another supplier, CNG acts as an agent and delivers the natural gas for that supplier. Revenue in those cases is only for providing the service of delivery of the natural gas.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as CNG delivers or sells the natural gas.

CNG also records revenue from an Alternative Revenue Program (ARP), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators.CNG ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

CNG also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing or ARPs.

Revenues disaggregated by major source for the year ended December 31, 2021 and 2020 are as follows:

Years Ended December 31,		2021		2020
(Thousands)				
Regulated operations – natural gas	$	402,429	$	354,341
Other(a)		95		662
Revenue from contracts with customers		**402,524**		**355,003**
Leasing revenue		—		101
Alternative revenue programs		15,525		13,446
Other revenue		1,025		—
Total operating revenues	**$**	**419,074**	**$**	**368,550**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting CNG.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of our cash flows and the rates of return market participants would require in order to invest their capital in CNG. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

For 2021, we utilized a qualitative assessment and for 2020, we utilized a quantitative assessment. We had no impairment of goodwill in 2021 and 2020 as a result of our impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2021 or 2020 that required us to update the assessment.

The carrying amount of goodwill, which resulted from the purchase of CNG by UIL Holdings in 2010, was $79.3 million at both December 31, 2021 and 2020, with no accumulated impairment losses and no changes during 2021 and 2020.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Current		
Federal	$ 3,502	$ (531)
State	2,094	(3,278)
Current taxes charged to expense (benefit)	**5,596**	**(3,809)**
Deferred		
Federal	4,901	8,772
State	(2,154)	6,067
Deferred taxes charged to expense	**2,747**	**14,839**
Total Income Tax Expense	**$ 8,343**	**$ 11,030**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Tax expense at federal statutory rate	$ 8,653	$ 8,081
Tax return related adjustments	310	203
State taxes, net of federal income tax	(47)	2,204
Other, net	(573)	542
Total Income Tax Expense	**$ 8,343**	**$ 11,030**

Income tax expense for the year ended December 31, 2021 was $0.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes which are partially offset by tax benefits from Excess ADIT amortization and AFUDC flow through adjustments. This resulted in an effective tax rate of 20.2%. Income tax expense for the year ended December 31, 2020 was $3.0 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, offset by a benefit in Depreciation, amortization and other plant differences not normalized. This resulted in an effective tax rate of 28.7%.

Deferred tax assets and liabilities as of December 31, 2021 and 2020 consisted of:

December 31,	2021	2020
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
CT credit carryforward	$ (6,551)	$ (5,362)
Valuation allowance - State Credits	$ 482	$ 1,955
Deferred tax liability on 2017 Tax Act remeasurement	(3,718)	(3,719)
Property related	38,268	30,971
Unfunded future income taxes	1,148	1,066
Goodwill	5,258	4,789
Pension (net)	343	509
Other	3,472	5,250
Total Non-current Deferred Income Tax Liabilities	**$ 38,702**	**$ 35,459**
Deferred tax assets	$ 10,269	$ 9,081
Deferred tax liabilities	48,971	44,540
Net Accumulated Deferred Income Tax Liabilities	**$ 38,702**	**$ 35,459**

As of December 31, 2021, CNG had a state net credit carry forward of $6.6 million and a state net operating loss carry forward of $1.4 million. As of December 31, 2020, CNG had a state net credit carry forward of $5.4 million and a state net operating loss carry forward of $0.8 million. CNG's state tax credit carry forwards will begin to expire for the 2021 tax year.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. For 2021, CNG has not recorded a valuation allowance on its state tax credit carryforwards.

Uncertain tax positions are classified as non-current unless expected to be paid within one year. We net our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income. As of December 31, 2021 and 2020, CNG did not have any gross income tax reserves for uncertain tax positions.

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information. CNG had no unrecognized income tax benefits as of December 31, 2021 or 2020.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2021 or 2020.

Note 7. Non-current Debt

Long-term debt as of December 31, 2021 and 2020 consisted of:

As of December 31,		**2021**		**2020**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2028-2049	$ 190,000	2.02%-6.66%	$ 190,000	2.02%-6.66%
Unamortized debt issuance costs and discount		(1,061)		(1,029)	
Total Debt		**188,939**		**188,971**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 188,939**		**$ 188,971**	

On December 15, 2020, CNG issued $30 million of notes with a maturity of 2030 and interest rate of 2.02%.

We have no long-term debt, including sinking fund obligations, due during the next five years through 2026.

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2021 and 2020.

Note 8. Bank Loans and Other Borrowings

CNG had $8.7 million of notes payable at December 31, 2021 and no debt outstanding at December 31, 2020. CNG funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the "Virtual Money Pool Agreement"), a bi-lateral intercompany credit agreement with Avangrid (the "Bi-Lateral Intercompany Facility") and a bank provided credit facility to which CNG is a party (the "AGR Credit Facility"), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CNG has a lending/borrowing limit of $100 million under this agreement. CNG had no debt outstanding under this agreement at December 31, 2021 and 2020.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CNG had $8.7 million outstanding under this agreement at December 31, 2021 and no debt outstanding at December 31, 2020.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), CNG, The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million, UI has $250 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10 to 22.5 basis points. CNG had not borrowed under this agreement as of both December 31, 2021 and 2020.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.32 to 1.00 at December 31, 2021. We are not in default as of December 31, 2021.

Note 9. Redeemable Preferred Stock

At December 31, 2021 and 2020, our redeemable preferred stock was:

Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding(1)	Amount (Thousands) 2021	2020
CNG, 8% Non-callable	$ 3.125	$ —	108,706	$ 340	$ 340
Total				**$ 340**	**$ 340**

(1) At December 31, 2021 CNG had $884,315 shares of $3.125 par value preferred stock authorized.

Note 10. Leases

We have operating leases for land, office buildings, facilities, and certain equipment. CNG does not have any finance leases. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 7 years, some of which may include options to extend the leases for up to 5 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

For the Years Ended December 31,	2021	2020
(Thousands)		
Lease cost		
Operating lease cost	$ 276	$ 1,382
Short-term lease cost	8	—
Variable lease cost	102	—
Total lease cost	**$ 386**	**$ 1,382**

Balance sheet and other information for the years ended December 31, 2021 and 2020 was as follows:

As of December 31,	2021	2020
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 542	$ 475
Operating lease liabilities, current	607	419
Operating lease liabilities, long-term	100	253
Total operating lease liabilities	$ 707	$ 672
Weighted-average Remaining Lease Term (years)		
Operating leases	2.79	1.27
Weighted-average Discount Rate		
Operating leases	1.29 %	1.41 %

For the years ended December 31, 2021 and 2020, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,		2021		2020
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	586	$	468
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	442	$	—

As of December 31, 2021, maturities of lease liabilities were as follows:

		Operating Leases
(Thousands)		
Year ending December 31,		
2022	$	495
2023		49
2024		68
2025		40
2026		26
Thereafter		42
Total lease payments		**720**
Less: imputed interest		(13)
Total	**$**	**707**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 11. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of natural gas service.

Site Decontamination, Demolition and Remediation Costs

CNG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. CNG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2021 and no amount of loss, if any, can be reasonably estimated at this time. In the past, CNG has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

CNG owns a property located on Columbus Boulevard in Hartford which is a former MGP site. Costs associated with the remediation of the site could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates. As of December 31, 2021, CNG has determined that remediation of the property in Hartford is not probable and therefore no amounts have been reserved.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $237 million and $257 million as of December 31, 2021 and 2020, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2021 and 2020 consist of:

Description	Total	(Level 1)	(Level 2)	(Level 3)
(Thousands)				
2021				
Assets				
Noncurrent investments	$ 833	$ 833	$ —	$ —
Total	**$ 833**	**$ 833**	**$ —**	**$ —**
2020				
Assets				
Noncurrent investments	$ 960	$ 960	$ —	$ —
Total	**$ 960**	**$ 960**	$ —	$ —

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2021 and 2020. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

<u>Valuation techniques</u>: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments primarily consist of money market funds.

Note 13. Post-Retirement and Similar Obligations

CNG has multiple qualified pension plans covering eligible union and management employees and retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. The plans are traditional defined benefit plans or cash balance plans depending on date of hire and are closed to new employees hired on or after specified dates. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution.

CNG non-union employees are eligible to participate in the UIL Holdings Corporation 401(k) Employee Stock Ownership Plan and union employees are eligible to participate in the Connecticut Natural Gas Corporation Union Employee 401(k) Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expenses under the Plan for the Company totaled approximately $1.7 million for 2021 and $1.6 million for 2020.

CNG also has plans providing other postretirement benefits for eligible employees and retirees. The plans were closed to newly-hired CNG union employees by end of March 2011. These benefits consist primarily of health care, prescription drug and life insurance benefits for retired employees and their dependents. For Medicare eligible non-union retirees, CNG provides a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other current and Other non-current liabilities on our balance sheets, was $1.3 million and $1.4 million at December 31, 2021 and 2020, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 319,796**	**$ 301,482**	**$ 19,090**	**$ 18,848**
Service cost	4,935	4,847	166	141
Interest cost	8,227	9,414	366	573
Actuarial loss (gain)	(15,619)	16,759	156	1,199
Curtailments/settlements	(1,113)	—	—	—
Benefits paid	(20,360)	(12,706)	(2,250)	(1,671)
Benefit obligation as of December 31,	**$ 295,866**	**$ 319,796**	**$ 17,528**	**$ 19,090**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 228,737**	**$ 203,341**	**$ 12,398**	**$ 11,499**
Actual return on plan assets	19,824	29,052	539	1,567
Employer contributions	2,680	9,050	1,550	1,003
Curtailments/settlements	(1,113)	—	—	—
Benefits paid	(20,360)	(12,706)	(2,250)	(1,671)
Fair value of plan assets at December 31,	**$ 229,768**	**$ 228,737**	**$ 12,237**	**$ 12,398**
Funded status at December 31,	**$ (66,098)**	**$ (91,059)**	**$ (5,291)**	**$ (6,692)**

During 2021, the pension benefit obligation had an actuarial gain of $15.6 million, primarily due to a $15.5 million gain from decreases in discount rates. There were no significant plan design changes in 2021. During 2021, the postretirement benefit obligations had an actuarial loss of $0.2 million.

During 2020, the pension benefit obligation had an actuarial loss of $16.8 million, primarily due to a $23.3 million loss from decreases in discount rates, partially offset by gains due to changes in mortality, demographic and other assumptions. There were no significant plan design changes in 2020. During 2020, the postretirement benefit obligations had an actuarial loss of $1.2 million.

Amounts recognized as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Non-current liabilities	$ (66,098)	$ (91,059)	$ (5,291)	$ (6,692)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Net loss (gain)	$ 27,568	$ 50,727	$ (1,696)	$ (1,868)
Prior service cost	$ —	$ —	$ 195	$ 396

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $276.3 million and $298.8 million as of December 31, 2021 and 2020. Our postretirement benefits were partially funded at December 31, 2021 and 2020.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2021 and 2020. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,	**2021**	**2020**
(Thousands)		
Projected benefit obligation	$ 295,866	$ 319,796
Accumulated benefit obligation	$ 276,311	$ 298,804
Fair value of plan assets	$ 229,768	$ 228,737

As of December 31, 2021 and 2020, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2021 and 2020 consisted of:

For the years ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 4,935	$ 4,847	$ 166	$ 141
Interest cost	8,227	9,414	366	572
Expected return on plan assets	(15,892)	(14,908)	(367)	(563)
Amortization of prior service cost (benefit)	—	—	201	201
Settlement charge	63	—	—	—
Amortization of net loss	3,546	3,675	(187)	(229)
Net Periodic Benefit Cost	**$ 879**	**$ 3,028**	**$ 179**	**$ 122**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net loss (gain)	$ (19,551)	$ 2,615	$ (15)	$ 196
Settlements	(63)	—	—	—
Amortization of net loss	(3,546)	(3,675)	187	229
Amortization of prior service (cost) benefit	—	—	(201)	(201)
Total Other Changes	**(23,160)**	**(1,060)**	**(29)**	**224**
Total Recognized	**$ (22,281)**	**$ 1,968**	**$ 150**	**$ 346**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate	2.96% / 3.06% / 2.85%	2.63%	2.61%	2.00%
Rate of compensation increase	3.50% / 3.00% / 2.90%	3.20%	N/A	N/A
Interest crediting rate	2.00% / 4.00% / 4.00%	3.17%	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rates by developing yield curves derived from a portfolio of high grade non-callable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate	2.56% / 2.70% / 2.43%	3.19 %	2.00 %	4.90 %
Expected long-term return on plan assets	7.00 %	7.40 %	2.96 %	4.90 %
Rate of compensation increase (Union/Non-Union)	3.50% / 3.00% / 2.90%	3.50 %	N/A	N/A

CNG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits.

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over ten years from the time they are incurred as required by the PURA. For pension benefits, CNG does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	2021	2020
Health care cost trend rate assumed for next year	N/A	6.50%/7.25%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	N/A	4.50 %
Year that the rate reaches the ultimate trend rate	N/A	2029/2027

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We expect to contribute $0.9 million and $1.1 million, respectively, to our pension and other postretirement benefit plans during 2022.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2021 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2022	$ 13,013	$ 1,621	$ 168
2023	$ 13,165	$ 1,507	$ 152
2024	$ 13,525	$ 1,408	$ 141
2025	$ 13,836	$ 1,292	$ 129
2026	$ 14,408	$ 1,231	$ 115
2027 - 2031	$ 78,331	$ 5,194	$ 417

Plan assets

Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust’s investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We currently have target allocations ranging from 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 5,186	$ 1,028	$ 4,158	$ —
U.S. government securities	13,314	13,314	—	—
Common stocks	10,078	10,078	—	—
Registered investment companies	22,086	22,086	—	—
Corporate bonds	60,480	—	60,480	—
Preferred stocks	65	65	—	—
Common collective trusts	83,418	—	83,418	—
Other, principally annuity, fixed income	1,616	1	1,615	—
	$ 196,243	**$ 46,572**	**$ 149,671**	**$ —**
Other investments measured at net asset value	33,525			
Total	**$ 229,768**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 3,907	$ 8	$ 3,899	$ —
U.S. government securities	13,224	13,220	4	—
Common stocks	7,798	7,798	—	—
Registered investment companies	22,261	22,261	—	—
Corporate bonds	52,918	—	52,918	—
Preferred stocks	73	73	—	—
Common collective trusts	85,295	—	85,295	—
Other, principally annuity, fixed income	317	475	(158)	—
	$ 185,793	**$ 43,835**	**$ 141,958**	**$ —**
Other investments measured at net asset value	42,944			
Total	**$ 228,737**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 29% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49%-69% for equity securities and 31%-51% for fixed income investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 185	$ 15	$ 170	$ —
U.S. government securities	229	229	—	—
Common stocks	141	141	—	—
Registered investment companies	319	319	—	—
Corporate bonds	885	—	885	—
Preferred stocks	1	1	—	—
Common collective trusts	1,295	—	1,295	—
Other, principally annuity, fixed income	8,700	—	8,700	—
	$ 11,755	**$ 705**	**$ 11,050**	**$ —**
Other investments measured at net asset value	482			
Total	**$ 12,237**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020	Fair Value Measurements			
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 615	$ —	$ 615	$ —
U.S. government securities	91	91	—	—
Common stocks	53	53	—	—
Registered investment companies	8,248	8,248	—	—
Corporate bonds	363	—	363	—
Preferred stocks	1	1	—	—
Common collective trusts	580	—	580	—
Other, principally annuity, fixed income	2,153	3	2,150	—
	$ 12,104	**$ 8,396**	**$ 3,708**	**$ —**
Other investments measured at net asset value	294			
Total	**$ 12,398**			

Valuation techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks and registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2021 and 2020.

Note 14. Other Income and Other Deductions

Other income and Other deductions for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,		2021		2020
(Thousands)				
Interest and dividends income	$	480	$	155
Allowance for funds used during construction		1,161		13
Carrying costs on regulatory assets		446		249
Miscellaneous		19		734
Total other income	**$**	**2,106**	**$**	**1,151**
Pension non-service components	$	(2,678)	$	(3,725)
Miscellaneous		(880)		(708)
Total other deductions	**$**	**(3,558)**	**$**	**(4,433)**

Note 15. Related Party Transactions

Certain Networks subsidiaries, including CNG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CNG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including CNG, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating services provided to CNG by AGR and its affiliates was approximately $21.3 million and $12.8 million for the years ended December 31, 2021 and 2020, respectively.

The balance in accounts payable to affiliates of $19.3 million at December 31, 2021 is mostly payable to UIL Holdings Corporation and the balance of $6.2 million at December 31, 2020 is payable to various companies. The balance in accounts receivable from affiliates of $0.7 million at December 31, 2021 and $2.4 million at December 31, 2020 is mostly receivable from SCG.

The balance in notes receivable from affiliates of $5.1 million at December 31, 2020 is from CMP. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

Note 16. Subsequent Events

The company has performed a review of subsequent events through March 31, 2022, which is the date these financial statements were available to be issued.

The Southern Connecticut Gas Company

Consolidated Financial Statements

As of and for the Years Ended December 31, 2021 and 2020

The Southern Connecticut Gas Company

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
The Southern Connecticut Gas Company:

Opinion

We have audited the consolidated financial statements of The Southern Connecticut Gas Company and its subsidiaries (the Company), which comprise the consolidated balance sheets as of December 31, 2021 and 2020, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

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

Responsibilities of Management for the Consolidated Financial Statements

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

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

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

KPMG LLP

New York, New York
April 14, 2022

The Southern Connecticut Gas Company
Consolidated Statements of Income

Years Ended December 31,		2021		2020
(Thousands)				
Operating Revenues	$	**412,564**	$	**353,243**
Operating Expenses				
Natural gas purchased		180,914		133,789
Operations and maintenance		97,770		89,828
Depreciation and amortization		37,057		41,260
Taxes other than income taxes, net		33,670		30,654
Total Operating Expenses		**349,411**		**295,531**
Operating Income		**63,153**		**57,712**
Other income		2,298		2,258
Other deductions		(96)		(7,384)
Interest expense, net of capitalization		(16,503)		(15,636)
Income Before Income Tax		**48,852**		**36,950**
Income tax expense		11,873		10,748
Net Income		**36,979**		**26,202**
Less: net income attributable to noncontrolling interest		3,348		1,683
Net Income Attributable to SCG	$	**33,631**	$	**24,519**

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

The Southern Connecticut Gas Company
Consolidated Statements of Comprehensive Income

Years Ended December 31,		2021		2020
(Thousands)				
Net Income	$	**36,979**	$	**26,202**
Other Comprehensive Loss, Net of Tax				
Amortization of pension cost for non-qualified plans, net of income tax benefit of ($477) for 2021 and ($1,323) for 2020		(1,295)		(5,032)
Total Other Comprehensive Loss, Net of Tax		**(1,295)**		**(5,032)**
Comprehensive Income		**35,684**		**21,170**
Less: Comprehensive income attributable to noncontrolling interest		3,348		1,683
Comprehensive Income Attributable to SCG	$	**32,336**	$	**19,487**

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

The Southern Connecticut Gas Company
Consolidated Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 473	$ 3,019
Accounts receivable and unbilled revenues, net	103,731	87,314
Accounts receivable from affiliates	1,529	4,558
Notes receivable from affiliates	28,956	6,529
Gas in storage	34,535	25,489
Materials and supplies	3,072	1,860
Income tax receivable	—	9,696
Other current assets	389	424
Regulatory assets	38,738	27,707
Total Current Assets	**211,423**	**166,596**
Utility plant, at original cost	1,230,436	1,159,949
Less accumulated depreciation	(347,760)	(321,380)
Net Utility Plant in Service	**882,676**	**838,569**
Construction work in progress	36,753	26,266
Total Utility Plant	**919,429**	**864,835**
Operating lease right-of-use assets	8,197	461
Other property and investments	11,787	10,683
Regulatory and Other Assets		
Regulatory assets	141,733	133,522
Goodwill	134,931	134,931
Other	372	181
Total Regulatory and Other Assets	**277,036**	**268,634**
Total Assets	**$ 1,427,872**	**$ 1,311,209**

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

The Southern Connecticut Gas Company
Consolidated Balance Sheets

As of December 31,	2021	2020
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$ —	$ 25,911
Notes payable to affiliates	3,580	19,028
Accounts payable and accrued liabilities	66,704	58,011
Accounts payable to affiliates	20,005	7,012
Interest accrued	3,828	4,254
Taxes accrued	30,376	5,180
Operating lease liabilities	644	601
Regulatory liabilities	9,893	11,672
Other	23,011	11,541
Total Current Liabilities	**158,041**	**143,210**
Regulatory and Other Liabilities		
Regulatory liabilities	220,140	213,971
Other Non-current Liabilities		
Deferred income taxes	85,996	75,083
Pension and other postretirement	50,637	64,518
Operating lease liabilities	7,682	267
Asset retirement obligation	12,654	12,599
Environmental remediation costs	60,714	41,464
Other	6,885	8,949
Total Regulatory and Other Liabilities	**444,708**	**416,851**
Non-current debt	305,316	267,658
Total Liabilities	**908,065**	**827,719**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($13.33 par value, 2,650,000 shares authorized and 1,407,072 shares outstanding at December 31, 2021 and 2020)	18,761	18,761
Additional paid-in capital	412,737	427,737
Retained earnings	52,798	19,167
Accumulated other comprehensive loss	(6,327)	(5,032)
Total SCG Common Stock Equity	**477,969**	**460,633**
Noncontrolling interest	41,838	22,857
Total Equity	**519,807**	**483,490**
Total Liabilities and Equity	**$ 1,427,872**	**$ 1,311,209**

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

The Southern Connecticut Gas Company
Consolidated Statements of Cash Flows

Years Ended December 31,	2021	2020
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 36,979**	**$ 26,202**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	37,057	41,260
Regulatory assets/liabilities amortization	13,935	(1,641)
Regulatory assets/liabilities carrying cost	2,314	1,945
Amortization of debt issuance costs	(2,750)	299
Deferred taxes	11,166	21,892
Pension cost	(497)	5,040
Accretion expenses	646	—
Other non-cash items	56	3,174
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(13,388)	(1,004)
Inventories	(10,258)	3,786
Accounts payable, to affiliates, and accrued liabilities	22,677	(3,735)
Taxes accrued	34,892	(9,940)
Other assets/liabilities	23,283	(6,054)
Regulatory assets/liabilities	(49,012)	(82)
Net Cash Provided by Operating Activities	**107,100**	**81,142**
Cash Flow from Investing Activities:		
Capital expenditures	(90,222)	(88,952)
Contributions in aid of construction	2,864	—
Proceeds from sale of utility plant	43	—
Notes receivable from affiliates	(22,427)	(5,391)
Net Cash Used in Investing Activities	**(109,742)**	**(94,343)**
Cash Flow from Financing Activities:		
Non-current debt issuance	39,911	50,000
Repayment of non-current debt	(25,000)	—
Return of capital	(40,000)	—
Notes payable to affiliates	(15,448)	(19,321)
Capital contributions	25,000	40,000
Contributions from noncontrolling interest	19,431	—
Dividends paid	—	(55,000)
Payment of noncontrolling interest dividend	(3,798)	—
Other	—	(295)
Net Cash Provided by Financing Activities	**96**	**15,384**
Net (Decrease) Increase in Cash and Cash Equivalents	**(2,546)**	**2,183**
Cash and Cash Equivalents, Beginning of Period	**3,019**	**836**
Cash and Cash Equivalents, End of Period	**$ 473**	**$ 3,019**

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

The Southern Connecticut Gas Company
Consolidated Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of Shares (*)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Common Stock Equity
Balance, December 31, 2019	**1,407,072**	**$ 18,761**	**$ 387,737**	**$ 49,648**	**$ —**	**$ 21,174**	**$ 477,320**
Net income	—	—	—	24,519	—	—	24,519
Other comprehensive loss, net of tax	—	—	—	—	(5,032)	—	(5,032)
Comprehensive income							19,487
Net income attributable to noncontrolling interest	—	—	—	—	—	1,683	1,683
Common stock dividends	—	—	—	(55,000)	—	—	(55,000)
Capital contributions	—	—	40,000	—	—	—	40,000
Balance, December 31, 2020	**1,407,072**	**18,761**	**427,737**	**19,167**	**(5,032)**	**22,857**	**483,490**
Net income	—	—	—	33,631	—	—	33,631
Other comprehensive loss, net of tax	—	—	—	—	(1,295)	—	(1,295)
Comprehensive income							32,336
Net income attributable to noncontrolling interest	—	—	—	—	—	3,348	3,348
Payment of noncontrolling interest dividend	—	—	—	—	—	(3,798)	(3,798)
Contributions from noncontrolling interest	—	—	—	—	—	19,431	19,431
Capital contributions	—	—	25,000	—	—	—	25,000
Return of capital	—	—	(40,000)	—	—	—	(40,000)
Balance, December 31, 2021	**1,407,072**	**$ 18,761**	**$ 412,737**	**$ 52,798**	**$ (6,327)**	**$ 41,838**	**$ 519,807**

(*) Par value of share amounts is $13.33

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

Notes to Consolidated Financial Statements

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

Background and nature of operations: The Southern Connecticut Gas Company (SCG, the company, we, our, us) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 207,000 customers as of December 31, 2021, in its service territory of approximately 555 square miles. SCG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

SCG is the principal operating utility of Connecticut Energy Corporation (CEC), a wholly-owned subsidiary of UIL Holdings Corporation (UIL Holdings). CEC is a holding company whose sole business is ownership of its operating regulated gas utility. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

Variable Interest Entities: CNE Peaking LLC (CNE) and Total Peaking Services LLC (TPS), both wholly-owned subsidiaries of United Resources, Inc. (URI), which is a wholly-owned subsidiary of UIL Holdings, own a 14.6 million gallon liquefied natural gas (LNG) storage tank operated by SCG and located on property owned by SCG in Milford, Connecticut, and certain equipment, materials and supplies used in or useful for the operation of the storage tank. The assets earn a rate of return equal to SCG's allowed rate of return. CNE and TPS have been identified as Variable Interest Entities (VIEs). SCG has been determined to be the primary beneficiary as SCG has the power to direct significant activities at CNE and TPS with SCG operating the storage tank and all of the revenues at CNE and TPS being derived from SCG. As a result, CNE and TPS have been consolidated into the financial statements of SCG, which include total assets of $49.9 million and income of $3.3 million as of and for the year ended December 31, 2021. Intercompany operating revenues and natural gas purchased expenses and intercompany receivables and payables have been eliminated upon consolidation. The equity interests in CNE and TPS held by URI are reflected as a noncontrolling interest in the accompanying consolidated balance sheets and consolidated statement of changes in common stock equity.

The liabilities recognized as a result of combining the above VIEs do not necessarily represent additional claims on SCG's general assets outside of the VIEs; rather they represent claims against the specific assets of the combined VIEs. Conversely, assets recognized as a result of combining these VIEs do not necessarily represent additional assets that could be used to satisfy claims against SCG's general assets. The total combined VIE assets and liabilities reflected on SCG's consolidated balance sheets are as follows:

As of December 31,	2021	2020
(Thousands)		
Assets		
Current assets	$ 20,276	$ 12,001
Long-term assets	29,600	30,502
Total Assets	**49,876**	**42,503**
Liabilities		
Current liabilities	8,038	19,646
Total Liabilities	**$ 8,038**	**$ 19,646**

Notes to Consolidated Financial Statements

Basis of presentation: The accompanying consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and are prepared on a consolidated basis, and therefore include the accounts of SCG and all SCG VIEs where SCG has identified that it is the primary beneficiary. All intercompany transactions and accounts have been eliminated in consolidation in all periods presented.

Significant Accounting Policies: We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our consolidated financial statements:

Principles of consolidation: We consolidate the entities in which we have a controlling financial interest, after the elimination of intercompany transactions. We account for investments in common stock where we have the ability to exercise significant influence, but not control, using the equity method of accounting.

Revenue recognition: We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

Regulatory accounting: We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our consolidated statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

Noncontrolling interest: The noncontrolling interest represents the portion of our net income (loss), comprehensive income (loss) and net assets that is not allocable to us and is calculated based on our ownership percentage.

Goodwill: Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred, the fair value of any noncontrolling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

***Utility plant*:** We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.9% of average depreciable property for 2021 and 3.7% for 2020. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 10 years. Depreciation expense was $34.1 million in 2021 and $34.3 million in 2020. Amortization of capitalized software was $3 million in 2021 and $7 million in 2020.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	Estimated useful life range (years)		2021		2020
(Thousands)					
Gas distribution plant	6-78	$	1,093,369	$	1,003,922
Software	3-10		51,871		38,131
Land	N/A		7,658		3,747
Building and improvements	40-50		28,788		28,456
VIE	10-50		43,368		41,365
Other plant	25-39		5,382		44,328
Total Utility Plant in Service			**1,230,436**		**1,159,949**
Total accumulated depreciation			(347,760)		(321,380)
Total Net Utility Plant in Service			**882,676**		**838,569**
Construction work in progress			36,753		26,266
Total Utility Plant		**$**	**919,429**	**$**	**864,835**

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our consolidated balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the consolidated balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

***Fair value measurement*:** 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

***Cash and cash equivalents*:** Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our consolidated balance sheets. We report changes in book overdrafts in the operating activities section of the consolidated statements of cash flows.

Consolidated statements of cash flows: Supplemental disclosure of cash flow information is as follows:

(Thousands)		2021		2020
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	13,637	$	12,898
Income taxes refunded, net	$	(32,138)	$	(12,108)

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. After completing its 2020 Connecticut income tax return in the fall of 2021, AVANGRID determined that it could not provide a current benefit for loss to SCG for its 2020 stand-alone loss that was settled in March 2021. As a result, SCG reversed a current tax benefit for this loss and replaced it with a $5.1M (tax effected) increase to its CT Net Operating Loss. SCG reimbursed its Parent in March 2022.

Interest capitalized was $0.4 million in 2021 and in $0.1 million in 2020. Accrued liabilities for utility plant additions were $6.2 million in 2021 and $8.9 million in 2020.

***Trade receivables and unbilled revenues, net*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing trade receivables, determined based on experience. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $25.8 million for 2021 and $21.1 million for 2020, and are shown net of an allowance for credit losses at December 31 of $9.8 million for 2021 and $4.0 million for 2020. Trade receivable do not bear interest, although late fees may be assessed. Credit loss expense was $9.1 million in 2021 and $7.8 million in 2020.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

Debentures, bonds and bank borrowings: We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our consolidated balance sheets.

***Gas in storage**: We own natural gas that is stored in both self-owned and third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our consolidated balance sheets within “Gas in storage.”

Materials and supplies: Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the consolidated balance sheets within “Materials and supplies.” We combine inventory items for the consolidated statement of cash flows presentation purposes.

Government grants: We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the consolidated statements of income in the period in which we incur the expenses.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our consolidated balance sheets and amortize them into earnings when revenue recognition criteria are met.

Asset retirement obligations**:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl-contaminated equipment, gas pipeline and cast iron gas mains. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2021 and 2020.

Years ended December 31,		2021		2020
(Thousands)				
ARO, beginning of year	$	12,599	$	12,434
Liabilities settled during the year		(591)		(488)
Accretion expense		646		653
ARO, end of year	**$**	**12,654**	**$**	**12,599**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Accrued removal obligations**:** We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2049.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain non-qualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the PURA. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

***Income taxes*:** AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, SCG settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax payable to AGR at December 31, 2021 is $24.3 million. The aggregate amount of the related party income tax receivable from AGR at December 31, 2020 is $9.7 million.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2021 and 2020.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the consolidated balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current on our consolidated balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in “Taxes other than income taxes” and “Taxes accrued” in our consolidated financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the consolidated financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the consolidated financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in our consolidated statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management's best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the consolidated financial statements.

Reclassifications: Certain amounts reported in the consolidated financial statements in previous periods have been reclassified to conform to the current year presentation.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation; (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments; and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for: (1) franchise taxes that are partially based on income; (2) transactions with a government that result in a step up in the tax basis of goodwill; (3) separate financial statements of legal entities that are not subject to tax; and (4) enacted changes in tax laws in interim periods. We adopted the amendments effective January 1, 2021, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures. We are applying the amendments on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment requirement.

(b) Improvements to lessor accounting for certain leases with variable lease payments

In July 2021, the FASB issued amendments to make targeted improvements to ASC 842 for lessor's accounting for certain leases with variable lease payments, which affect lease classification. The amendments require a lessor to classify and account for a lease with variable lease payments as an operating lease if (a) the lease would have been classified as a sales-type lease or a direct financing lease and (b) the lessor would have otherwise recognized a day-one loss. The amendments are effective for fiscal years beginning after December 15, 2021, for all entities, and interim periods within those fiscal years for public business entities, with early application permitted. We have elected to early apply the amendments effective October 1, 2021, and apply the amendments prospectively to leases that commence or are modified on or after that date. Our adoption does not materially affect our consolidated results of operations, financial position and cash flows.

(c) Accounting for revenue contracts with customers acquired in a business combination

In October 2021, the FASB issued amendments related to the accounting for revenue contracts acquired in a business combination. The amendments require an entity (acquirer) to recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606, Revenue from Contracts with Customers. At the acquisition date, an acquirer should account for the related revenue contract in accordance with ASC 606 as if it had originated the contracts. Generally, this should result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree’s financial statements. The amendments also provide certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. For public business entities, the amendments are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The amendments should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted. We have elected to early apply the amendments effective October 1, 2021. Our adoption did not materially affect our consolidated results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2021, that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(a) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments were effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Our prospective adoption of ASC 848 on January 1, 2022 will not materially affect our consolidated results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

In November 2021, the FASB issued amendments that apply to business entities (all entities except specified not-for-profit entities and employee benefit plans) that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance (such as a grant model within International Accounting Standards 20 Accounting for Government Grants and Disclosure of Government Assistance, or ASC Subtopic 958-605, Not-For-Profit Entities—Revenue Recognition). Government assistance can include tax credits (excluding transactions within the scope of Topic 740, Income Taxes), cash grants, grants of other assets, and project grants. Often, government assistance is provided to an entity for a particular purpose, and the entity promises to take specific actions. Transactions with a government, as used in ASC 832, Government Assistance, include assistance administered by domestic, foreign, local (city, town, county, municipal), regional (state, provincial, territorial), and national (federal) governments and entities related to those governments. The amendments require annual disclosures in notes to financial statements about transactions with a government as follows: (1) information about the nature of the transactions and the related accounting policy used to account for the transactions, (2) the line items on the balance sheet and income statement affected by the transactions, and the amounts applicable to each financial statement line item, and (3) significant terms and conditions of the transactions, including commitments and contingencies. For entities within scope the amendments are effective for annual periods beginning after December 15, 2021, with early application permitted. The amendments are to be applied either (1) prospectively to transactions within the scope of the amendments that are reflected in financial statements at the date of initial application and new transactions that are entered into after the date of initial application or (2) retrospectively to those transactions. Our adoption of the amendments on January 1, 2022 will not materially affect our disclosures.

Use of estimates and assumptions: The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) earnings sharing mechanism (ESM); (10) environmental remediation liabilities; (11) pension and other postretirement employee benefits (OPEB); (12) fair value measurements; (13) AROs, and (14) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our consolidated financial results, actual results could differ from those estimates, which could result in material effects to our consolidated financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 76% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Rates

Utilities are entitled by Connecticut statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

In December 2017, PURA approved new tariffs for SCG effective January 1, 2018 for a three-year rate plan with rate increases of $1.5 million, $4.7 million and $5.0 million in 2018, 2019, and 2020, respectively. The new tariffs also include, among other things, an RDM and Distribution Integrity Management Program, earnings sharing mechanism (ESM), the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on a ROE of 9.25% and approximately 52% equity level. Any dollars due to customers from the ESM will be first applied against any environmental regulatory asset balance as defined in the settlement agreement (if one exists at that time) or refunded to customers through a bill credit if such environmental regulatory asset balance does not exist.

Additionally, SCG has a purchased gas adjustment clause, approved by PURA, which enables reasonably incurred cost of gas purchases to be passed through to customers. This clause allows utilities to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Gas Supply Arrangements

SCG satisfies its natural gas supply requirements through purchases from various producer/ suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. SCG operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by SCG are passed through to customers through state regulated purchased gas adjustment mechanisms subject to regulatory review.

SCG purchases the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. SCG diversifies its sources of supply by amount purchased and location. SCG primarily acquires gas at various locations in the US Gulf of Mexico region, in the Appalachia region and in Canada.

SCG acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline, Algonquin Gas Transmission and Iroquois Gas Transmission interconnect with SCG's distribution system and the other pipelines provide indirect services upstream of the city gates. The prices and terms and conditions of the firm transportation capacity long-term contracts for firm transportation capacity are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

SCG acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York, West Virginia and Michigan.

SCG has the rights to 100% of the Liquefied Natural Gas (LNG) stored in an LNG facility which is directly attached to its distribution system. SCG uses the LNG capacity as a winter peaking resource.

Minimum Equity Requirements for Regulated Subsidiaries

Pursuant to an agreement with PURA, SCG is restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, SCG is prohibited from paying dividends to their parent if the utility's credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility's credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable.

We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $107.1 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and non-current regulatory assets at December 31, 2021 and 2020 consisted of:

Notes to Consolidated Financial Statements

December 31,		2021		2020
(Thousands)				
Current				
Debt premium	$	910	$	910
Deferred purchased gas		16,752		10,377
Energy efficiency portfolio standard		2,279		—
Environmental remediation costs		362		362
Hardship programs		—		3,034
Pension and other postretirement benefits		—		4,385
Revenue decoupling mechanism		11,973		4,518
System expansion		5,454		—
Other		1,008		4,121
Total current regulatory assets		**38,738**		**27,707**
Non-current				
Asset retirement obligation		3,710		3,595
Debt premium		3,202		6,401
Environmental remediation costs		67,004		48,903
Pension and other postretirement benefits		63,501		72,215
Revenue decoupling mechanism		—		2,408
Other		4,316		—
Total non-current regulatory assets	**$**	**141,733**	**$**	**133,522**

Asset retirement obligations represent the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

Debt premium represents the regulatory asset recorded to offset the fair value adjustment to the regulatory component of the non-current debt of UIL at the acquisition date. This amount is being amortized to interest expense over the remaining term of the outstanding debt instruments.

Deferred purchased gas costs represents the difference between actual gas costs and gas costs collected in rates. Balances at the end of the rate year are normally recorded/returned in the next year.

Environmental remediation costs include spending that has occurred and is eligible for future return/recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Hardship programs represent hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

System expansion represents expenses not covered by System expansion rates related to expanding the natural gas system and converting customers to natural gas.

Other includes items such as Distribution integrity management (DIMP), deferred credit card fees, Environmental defense fund (EDF) legal costs and COVID-19 deferrals.

Current and non-current regulatory liabilities at December 31, 2021 and 2020 consisted of:

December 31,		**2021**		**2020**
(Thousands)				
Current				
Low income program	$	6,452	$	4,977
Non-firm margin sharing credits		—		2,123
Rate credits		750		750
Unfunded future income taxes		2,671		2,671
Other		20		1,151
Total current regulatory liabilities		**9,893**		**11,672**
Non-current				
Asset removal obligation		116,091		109,825
Low income program		13,705		23,077
Non-firm margin sharing credits		6,762		4,247
Pension and other postretirement benefits		5,192		3,421
Rate credits		3,750		4,500
Tax reform		57,596		47,542
Unfunded future income taxes		13,354		16,250
Other		3,690		5,109
Total non-current regulatory liabilities	**$**	**220,140**	**$**	**213,971**

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Low income program represents various hardship and payment plan programs approved for recovery.

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects.

Pension and other postretirement benefits represent the actuarial gains on pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future expenses. Because no funds have yet been received for this, a regulatory liability is not reflected within rate base. They also represent the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates.

Rate credits resulted from the acquisition of UIL by Iberdrola. This is being used to moderate increases in rates.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The amount and timing of potential settlement are determined by the regulated utilities' respective rate regulators and IRS Normalization rules.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes items such as Geographical information system (GIS) data conversion and various items subject to reconciliation.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

SCG derives its revenue primarily from tariff-based sales of natural gas service to customers in Connecticut with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Another major source of revenue is wholesale sales of natural gas.

Tariff-based sales are subject to PURA approval, which determine prices and other terms of service through the ratemaking process. Certain customers have the option to obtain the natural gas commodity directly from the utility or from another supplier. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the natural gas provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as SCG delivers or sells the natural gas.

SCG records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. This program, a revenue decoupling mechanism (RDM), represent a contract between the utilities and their regulators.

SCG also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

Revenues disaggregated by major source for the years ended December 31, 2021 and 2020 are as follows:

Years Ended December 31,	**2021**	**2020**
(Thousands)		
Regulated operations – natural gas	$ 396,739	$ 341,139
Other(a)	202	757
Revenue from contracts with customers	**396,941**	**341,896**
Leasing revenue	1	574
Alternative revenue programs	11,555	10,773
Other revenue	4,067	—
Total operating revenues	**$ 412,564**	**$ 353,243**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting SCG.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of our cash flows and the rates of return market participants would require in order to invest their capital in SCG. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

For 2021, we utilized a qualitative assessment and for 2020, we utilized a quantitative assessment. We had no impairment of goodwill in 2021 and 2020 as a result of our impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2021 or 2020 that required us to update the assessment.

The carrying amount of goodwill was $134.9 million at both December 31, 2021 and 2020, with no accumulated impairment losses and no changes during 2021 and 2020.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,		**2021**		**2020**
(Thousands)				
Current				
Federal	$	(844)	$	(3,642)
State		1,551		(7,502)
Current taxes charged to expense (benefit)		**707**		**(11,144)**
Deferred				
Federal		10,137		11,134
State		1,029		10,758
Deferred taxes charged to expense		**11,166**		**21,892**
Total Income Tax Expense	**$**	**11,873**	**$**	**10,748**

The differences between tax expense per the consolidated statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2021 and 2020, respectively, consisted of:

Years Ended December 31,		**2021**		**2020**
(Thousands)				
Tax expense at statutory rate	$	10,259	$	7,760
State tax expense, net of federal income tax benefit		2,038		2,572
Variable interest entity		(921)		(463)
Other, net		497		879
Total Income Tax Expense	**$**	**11,873**	**$**	**10,748**

Income tax expense for the year ended December 31, 2021 was $1.6 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, partially offset by AFUDC Equity tax effects. This resulted in an effective tax rate of 24.3%. Income tax expense for the year ended December 31, 2020 was $3.0 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes. This resulted in an effective tax rate of 29.1%.

Deferred tax assets and liabilities as of December 31, 2021 and 2020 consisted of:

December 31,		2021		2020
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	104,984	$	85,868
Unfunded future income taxes		(4,315)		(5,814)
Valuation allowance - state credits		6,586		4,865
Federal and state tax credits		(11,677)		(9,177)
Goodwill		19,989		18,201
Deferred tax asset on 2017 Tax Act remeasurement		(15,507)		(12,802)
Federal and state NOL's		(18,770)		(5,659)
Post-retirement benefits, net		2,615		2,318
Other		2,091		(2,717)
Total Non-current Deferred Income Tax Liabilities	**$**	**85,996**	**$**	**75,083**
Deferred tax assets	$	50,269	$	36,169
Deferred tax liabilities		136,265		111,252
Net Accumulated Deferred Income Tax Liabilities	**$**	**85,996**	**$**	**75,083**

SCG has federal net operating losses of $13.9 million, state net operating losses of $4.9 million and net state credit carryforward of $11.7 for the year ended December 31, 2021. SCG had federal net operating losses of $4.8 million, state net operating losses of $0.9 million and net state credit carryforward of $9.2 for the year ended December 31, 2020.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. As of December 31, 2021, SCG had recorded a valuation allowance on its state tax credit carryforwards of $6.6 million. As of December 31, 2020, SCG had recorded a valuation allowance on its state credit carryforwards of $4.9 million.

Uncertain tax positions are classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income. As of December 31, 2021 and 2020, SCG did not have any gross income tax reserves for uncertain tax positions.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2021 and 2020.

Note 7. Long-term Debt

Long-term debt as of December 31, 2021 and 2020 consisted of:

As of December 31,		2021		2020	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2025-2049	$ 304,000	1.87% - 7.95%	$ 289,000	1.87% - 7.95%
Unamortized debt issuance (costs) premium, net		1,316		4,569	
Total Debt		**305,316**		**293,569**	
Less: debt due within one year, included in current liabilities		—		25,911	
Total Non-current Debt		**$ 305,316**		**$ 267,658**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of SCG's properties.

On December 15, 2020, SCG issued $50 million of first mortgage bonds maturing in 2030 at an interest rate of 1.87%.

On December 15, 2021, SCG issued $40 million of first mortgage bonds maturing in 2031 at an interest rate of 2.05%.

Long-term debt, including sinking fund obligations, due over the next five years consist of:

2022	2023	2024	2025	2026	Total
(Thousands)					
$ —	$ —	$ —	$ 25,000	$ 15,000	$ 40,000

Under various long-term debt agreements, SCG is required to maintain a ratio of indebtedness to capital not to exceed 200% and to limit aggregate dividends paid pursuant specific indenture requirements. As of December 31, 2021 and 2020, SCG was in compliance with long-term debt covenants.

Note 8. Bank Loans and Other Borrowings

Notes payable balances totaled $3.6 million and $19.0 million as of December 31, 2021 and 2020, respectively. SCG funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which SCG is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. SCG has a lending/borrowing limit of $100 million under this agreement. SCG had no debt outstanding under this agreement at December 31, 2021 and 2020.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. SCG had no debt outstanding under this agreement at December 31, 2021 and 2020.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation (“NYSEG”), Rochester Gas and Electric Corporation (“RG&E”), Central Maine Power Company (“CMP”), The United Illuminating Company (“UI”), Connecticut Natural Gas Corporation (“CNG”), SCG, and The Berkshire Gas Company (“BGC”)) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23 2021, the AGR Credit Facility was amended to increase AGR’s maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. SCG had no outstanding balance as of December 31, 2021 and 2020.

In the AGR Credit Facility we covenant not to permit, without the consent of the lenders, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants beyond any applicable cure period, constitutes an event of default, and events of default could result in termination or reduction of lenders’ commitments or acceleration of amounts owed under the facility. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.37 to 1.00 at December 31, 2021. We are not in default as of December 31, 2021.

CNE and TPS each have a current account agreement with Avangrid whereby they can lend excess cash to Avangrid or borrow from Avangrid when they have cash funding needs to meet their obligations. Interest is charged at a rate equal to three-month LIBOR plus an applicable margin and is capitalized annually. As of December 31, 2021 and 2020 TPS had $3.6 million and $19 million, respectively, outstanding under its agreement. CNE did not have any amounts outstanding under its agreement as of December 31, 2021 and 2020.

Note 9. Preferred Stock

At December 31, 2021, SCG had 200,000 shares of $100 par value preferred stock and 1,600,000 shares of $2 par value preferred stock authorized but unissued.

Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. As of December 31, 2021 and 2020, we had no finance leases. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 to 52 years, some of which may include options to extend the leases for up to 20 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

Years Ended December 31,		2021		2020
(Thousands)				
Lease cost				
Operating lease cost	$	16	$	1,370
Short-term lease cost		7		—
Variable lease cost		365		—
Total lease cost	**$**	**388**	**$**	**1,370**

Consolidated balance sheet and other information for the years ended December 31, 2021 and 2020 was as follows:

As of December 31,		2021		2020
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right of use assets	$	8,197	$	461
Operating lease liabilities, current		644		601
Operating lease liabilities, long-term		7,682		267
Total operating lease liabilities	$	8,326	$	868
Weighted-average Remaining Lease Term (years):				
Operating leases		10.82		2.04
Weighted-average Discount Rate:				
Operating leases		1.99 %		2.69 %

Supplemental consolidated cash flows information related to leases was as follows:

Years Ended December 31,		2021		2020
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	1,204	$	91
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	8,513	$	—

Maturities of lease liabilities were as follows:

(Thousands)		Operating
Years Ended December 31,		
2022	$	770
2023		785
2024		1,370
2025		729
2026		746
Thereafter		4,834
Total lease payments		**9,234**
Less: imputed interest		(908)
Total	**$**	**8,326**

Most of our leases do not provide an implicit rate in the lease, thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 11. Environmental Liability

In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, climate change and electric and magnetic fields, we may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, as well as additional operating expenses. The total amount of these expenditures is not now determinable. Significant environmental issues known to SCG at this time are described below.

Site Decontamination, Demolition and Remediation Costs

SCG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. SCG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2021 and no amount of loss, if any, can be reasonably estimated at this time. In the past, SCG has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

SCG owns properties on Housatonic Avenue and Pine Street in Bridgeport, and on Chapel Street in New Haven, which are former MGP sites. Costs associated with the remediation of the sites could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates. As of December 31, 2021, SCG reserved $50.1 million related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2021, SCG reserved $12.8 million related to the property located on Pine Street in

Bridgeport. As of December 31, 2021, SCG has determined that remediation of the property on Housatonic Avenue in Bridgeport is not estimable at this time and therefore not reserved.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $369 million and $382 million as of December 31, 2021 and 2020, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2021 and 2020 consisted of:

Description	(Level 1)	(Level 2)	(Level 3)	Total
(Thousands)				
As of December 31, 2021				
Assets				
Non-current investments	$ 11,787	$ —	$ —	$ 11,787
Total	**$ 11,787**	**$ —**	**$ —**	**$ 11,787**
As of December 31, 2020				
Assets				
Non-current investments	$ 10,683	$ —	$ —	$ 10,683
Total	**$ 10,683**	**$ —**	**$ —**	**$ 10,683**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2021 and 2020. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

Note 13. Post-retirement and Similar Obligations

SCG has multiple qualified pension plans covering eligible union and management employees and retirees. The plans are traditional defined benefit plans or cash balance plans depending on date of hire and are closed to new employees hired on or after specified dates. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution. On March 31, 2022, the Board approved to freeze the SCG non-union plan, with an effective date of June 30, 2022.

SCG employees are eligible to participate in the UIL Holdings Corporation 401(k) Employee Stock Ownership Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expense totaled approximately $2.1 million for 2021 and $1.2 million for 2020.

SCG has plans providing other postretirement benefits for eligible employees and retirees. The plans were closed to newly-hired non-union employees at the end of 1995 and to newly-hired union employees by the end of March 2010. These benefits consist primarily of health care, prescription drug and life insurance benefits for retired employees and their dependents. For Medicare eligible non-union retirees, SCG provides a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our consolidated balance sheets, was $6.1 million and $6.6 million at December 31, 2021 and 2020, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 194,920	$ 178,707	$ 18,204	$ 18,639
Service cost	2,132	2,109	101	111
Interest cost	4,436	5,546	402	571
Plan participants' contributions	1,777	—	1,189	—
Actuarial (gain)/loss	(9,716)	18,214	892	562
Benefits paid	(14,065)	(9,656)	(2,365)	(1,679)
Benefit obligation at December 31	**$ 179,484**	**$ 194,920**	**$ 18,423**	**$ 18,204**
Change in plan assets				
Fair value of plan assets at January 1	$ 143,821	$ 129,517	$ 4,785	$ 5,151
Actual return on plan assets	12,254	18,071	522	552
Employer & plan participants' contributions	737	5,889	1,581	761
Benefits paid	(14,065)	(9,656)	(2,365)	(1,679)
Fair value of plan assets at December 31	**$ 142,747**	**$ 143,821**	**$ 4,523**	**$ 4,785**
Funded status	**$ (36,737)**	**$ (51,099)**	**$ (13,900)**	**$ (13,419)**

During 2021, the pension benefit obligation had an actuarial gain of $9.7 million. This gain was primarily driven by a $10.9 million gain from increase in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2020, the pension benefit obligation had an actuarial loss of $18.2 million. This loss was primarily driven by a $18.2 million loss from decrease in discount rates. There were no significant plan design changes in 2020. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the consolidated balance sheet as of December 31, 2021 and 2020 consisted of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2021**	**2020**	**2021**	**2020**
(Thousands)					
Noncurrent liabilities	$	(36,737)	$ (51,099)	$ (13,900)	$ (13,419)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities consist of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2021**	**2020**	**2021**	**2020**
(Thousands)					
Net actuarial loss(gain)	$	22,614	$ 37,520	$ (1,122)	$ (2,054)
Prior service cost	$	1,777	$ —	$ 1,298	$ 187

Our accumulated benefit obligation for all qualified defined benefit pension plans was $175.9 million and $191.5 million as of December 31, 2021 and 2020, respectively. SCG's postretirement benefits were partially funded as of December 31, 2021 and 2020.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2021 and 2020. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2021 and 2020.

As of December 31,		**2021**		**2020**
(Thousands)				
Projected benefit obligation	$	179,484	$	194,920
Accumulated benefit obligation	$	175,874	$	191,535
Fair value of plan assets	$	142,747	$	143,821

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2021 and 2020.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2021 and 2020 consisted of:

Notes to Consolidated Financial Statements

Years Ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net periodic benefit cost				
Service cost	$ 2,132	$ 2,109	$ 101	$ 111
Interest cost	4,436	5,546	402	571
Expected return on plan assets	(9,904)	(9,443)	(317)	(361)
Amortization of prior service cost	—	152	78	118
Amortization of actuarial loss (gain)	2,840	2,134	(246)	(309)
Net periodic benefit cost	**$ (496)**	**$ 498**	**$ 18**	**$ 130**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Current year actuarial (gain) loss	$ (12,065)	$ 9,585	$ 686	$ 371
Amortization of actuarial (loss) gain	(2,840)	(2,134)	246	309
Current year prior service costs	1,777	—	1,189	—
Amortization of prior service cost	—	(152)	(78)	(118)
Total recognized in regulatory assets and regulatory liabilities	**$ (13,128)**	**$ 7,299**	**$ 2,043**	**$ 562**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (13,624)**	**$ 7,797**	**$ 2,061**	**$ 692**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate	2.85 %	2.31 %	2.61 %	2.29 %
Rate of compensation increase	3.50%/ N/A Union	3.26 %	N/A	N/A
Interest crediting rate	2.00% / 4.00%	2.65 %	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate developing a yield curve derived from a portfolio of high grade non-callable bonds with yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
Discount rate	2.29% / 2.43%	3.19 %	2.29 %	3.19 %
Expected long-term return on plan assets	7.00 %	7.40 %	6.62 %	7.00 %
Rate of compensation increase	3.50% / 2.75%	3.5 %	N/A	N/A

SCG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits.

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred as required by the PURA. For pension benefits, SCG does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

Assumed health care cost trend rates to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	2021	2020
Health care cost trend rate (pre 65/post 65)	6.25% / 7.00%	6.50% / 7.25%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029 / 2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $1.0 million to our pension benefits plan in 2022. We expect to contribute $1.1 million to our postretirement benefits plan in 2022.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2022	$ 10,052	$ 1,621	$ 94
2023	$ 10,036	$ 1,472	$ 81
2024	$ 10,202	$ 1,382	$ 70
2025	$ 10,259	$ 1,295	$ 61
2026	$ 10,441	$ 1,189	$ 57
2027-2031	$ 52,478	$ 5,138	$ 282

Plan assets: Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets as of December 31, 2021, by asset category, consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 2,094	$ 649	$ 1,445	$ —
U.S. government securities	8,401	8,401	—	—
Common stocks	6,350	6,350	—	—
Registered investment companies	12,974	12,974	—	—
Corporate bonds	38,221	—	38,221	—
Preferred stocks	41	41	—	—
Common collective trusts	49,995	—	49,995	—
Other, principally annuity, fixed income	1,019	—	1,019	—
	$ 119,095	**$ 28,415**	**$ 90,680**	**$ —**
Other investments measured at net asset value	23,652			
Total	**$ 142,747**			

The fair values of pension benefits plan assets as of December 31, 2020, by asset category, consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2020				
Cash and cash equivalents	$ 1,686	$ 5	$ 1,681	$ —
U.S. government securities	8,352	8,349	3	—
Common stocks	4,922	4,922	—	—
Registered investment companies	14,074	14,074	—	—
Corporate bonds	33,421	—	33,421	—
Preferred stocks	46	46	—	—
Common collective trusts	53,988	—	53,988	—
Other, principally annuity, fixed income	200	300	(100)	—
	$ 116,689	**$ 27,696**	**$ 88,993**	**$ —**
Other investments measured at net asset value	27,132			
Total	**$ 143,821**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance.

This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. The postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49% - 69% for equity securities, 31%- 51% for fixed income. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2021 consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 276	$ 16	$ 260	$ —
U.S. government securities	223	223	—	—
Common stocks	146	146	—	—
Registered investment companies	1,103	1,103	—	—
Corporate bonds	919	—	919	—
Preferred stocks	1	1	—	—
Common collective trusts	1,348	—	1,348	—
Other, principally annuity, fixed income	28	—	28	—
	$ 4,044	**$ 1,489**	**$ 2,555**	**$ —**
Other investments measured at net asset value	479			
Total	**$ 4,523**			

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2020 consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2020				
Cash and cash equivalents	$ 237	$ —	$ 237	$ —
U.S. government securities	35	35	—	—
Common stocks	21	21	—	—
Registered investment companies	3,184	3,184	—	—
Corporate bonds	140	—	140	—
Preferred stocks	—	—	—	—
Common collective trusts	224	—	224	—
Other, principally annuity, fixed income	831	1	830	—
	$ 4,672	**$ 3,241**	**$ 1,431**	**$ —**
Other investments measured at net asset value	113			
Total	**$ 4,785**			

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2021 and 2020.

Note 14. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2021 and 2020, consisted of:

Years Ended December 31,		2021		2020
(Thousands)				
Interest and dividend income	$	998	$	1,445
Carrying costs on regulatory assets		434		218
Allowance for funds used during construction		847		(70)
Miscellaneous		19		665
Total other income	**$**	**2,298**	**$**	**2,258**
Pension non-service components	$	1,926	$	(3,323)
Miscellaneous		(2,022)		(4,061)
Total other deductions	**$**	**(96)**	**$**	**(7,384)**

Note 15. Related Party Transactions

Certain Networks subsidiaries, including SCG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For SCG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including SCG, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating services provided to SCG by AGR and its affiliates was approximately $19.1 million and $15.4 million for the years ended December 31, 2021 and 2020.

The balance in accounts payable to affiliates of $20 million at December 31, 2021 and the balance of $7 million at December 31, 2020 is mostly payable to UIL Holdings. The balance in accounts receivable from affiliates of $1.5 million at December 31, 2021 is mostly receivable from CNG and the balance of $4.6 million at December 31, 2020 is mostly receivable from UIL Holdings. The balance in notes receivable from affiliates of $29 million at December 31, 2021 is receivable from RGE and Avangrid. The balance of notes receivable from affiliates of $6.5 million at December 31, 2020 is receivable from CMP and Avangrid. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these consolidated financial statements.

Note 16. Subsequent Events

The company has performed a review of subsequent events through April 14, 2022, which is the date these consolidated financial statements were available to be issued.

The United Illuminating Company
Financial Statements
As of and for the Years Ended December 31, 2021 and 2020

The United Illuminating Company

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
The United Illuminating Company:

Opinion

We have audited the financial statements of The United Illuminating Company (the Company), which comprise the balance sheets as of December 31, 2021 and 2020, and the related statements of income, comprehensive income, changes in common stock equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

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

Responsibilities of Management for the Financial Statements

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

KPMG LLP

New York, New York
April 14, 2022

The United Illuminating Company
Statements of Income

Years Ended December 31,		2021		2020
(Thousands)				
Operating Revenues	$	**1,070,905**	$	**1,046,846**
Operating Expenses				
Electricity purchased		302,133		265,149
Operations and maintenance		390,980		371,604
Depreciation and amortization		111,204		108,205
Taxes other than income taxes, net		102,750		112,674
Total Operating Expenses		**907,067**		**857,632**
Operating Income		**163,838**		**189,214**
Other income		23,134		12,974
Other deductions		(3,199)		(13,208)
Earnings from equity method investments		6,357		8,249
Interest expense, net of capitalization		(39,958)		(44,352)
Income Before Income Tax		**150,172**		**152,877**
Income tax expense		24,795		31,637
Net Income	$	**125,377**	$	**121,240**

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

The United Illuminating Company
Statements of Comprehensive Income

Years Ended December 31,		2021		2020
(Thousands)				
Net Income	$	**125,377**	$	**121,240**
Other Comprehensive Loss				
Amortization of pension cost for non-qualified plans, net of income tax benefit of ($1,588) and ($2,245), respectively		(3,837)		(6,589)
Unrealized loss during the year on derivatives qualifying as cash flow hedges, net of income tax benefit of ($7) and $0, respectively		(16)		—
Other Comprehensive Loss		**(3,853)**		**(6,589)**
Comprehensive Income	$	**121,524**	$	**114,651**

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

The United Illuminating Company
Balance Sheets

As of December 31,	2021	2020
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ —	$ 169
Accounts receivable and unbilled revenues, net	147,782	170,913
Accounts receivable from affiliates	1,165	15,171
Notes receivable from affiliates	64,600	14,975
Materials and supplies	9,792	6,264
Derivative assets	427	390
Prepayments and other current assets	3,822	14,662
Income tax receivable	—	10,536
Regulatory assets	44,318	44,415
Total Current Assets	**271,906**	**277,495**
Utility plant, at original cost	3,485,699	3,335,542
Less accumulated depreciation	(958,844)	(863,071)
Net Utility Plant in Service	**2,526,855**	**2,472,471**
Construction work in progress	216,553	193,545
Total Utility Plant	**2,743,408**	**2,666,016**
Operating lease right-of-use assets	11,339	10,041
Equity method investments	86,557	90,951
Other property and investments	15,655	14,513
Regulatory and Other Assets		
Regulatory assets	370,194	411,926
Derivative assets	1,284	1,648
Other	22,378	2,489
Total Regulatory and Other Assets	**393,856**	**416,063**
Total Assets	**$ 3,522,721**	**$ 3,475,079**

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

The United Illuminating Company
Balance Sheets

As of December 31,		2021		2020
(Thousands)				
Liabilities				
Current Liabilities				
Current portion of debt	$	162,137	$	—
Accounts payable and accrued liabilities		140,732		135,721
Accounts payable to affiliates		69,991		28,631
Interest accrued		11,166		11,587
Taxes accrued		26,975		16,344
Operating lease liabilities		1,002		1,510
Derivative liabilities		14,586		13,378
Other current liabilities		37,701		30,896
Regulatory liabilities		45,113		16,430
Total Current Liabilities		**509,403**		**254,497**
Regulatory and Other Liabilities				
Regulatory liabilities		352,021		385,474
Other Non-current liabilities				
Deferred income taxes		389,550		379,659
Pension and other postretirement		162,445		204,713
Operating lease liabilities		14,644		12,806
Derivative liabilities		45,820		57,844
Environmental remediation costs		22,134		22,034
Other		30,987		17,432
Total Regulatory and Other Liabilities		**1,017,601**		**1,079,962**
Non-current debt		725,071		886,927
Total Liabilities		**2,252,075**		**2,221,386**
Commitments and Contingencies				
Common Stock Equity				
Common stock (no par value, 30,000,000 shares authorized and 100 shares outstanding at December 31, 2021 and December 31, 2020)		1		1
Additional paid-in capital		806,659		806,230
Retained earnings		474,428		454,051
Accumulated other comprehensive loss		(10,442)		(6,589)
Total Common Stock Equity		**1,270,646**		**1,253,693**
Total Liabilities and Equity	**$**	**3,522,721**	**$**	**3,475,079**

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

The United Illuminating Company
Statements of Cash Flows

Years Ended December 31,	2021	2020
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 125,377**	**$ 121,240**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	111,204	108,205
Regulatory assets/liabilities amortization	(60,670)	2,706
Regulatory assets/liabilities carrying cost	(8,489)	1,402
Amortization of debt issuance costs	613	739
Deferred taxes	(6,339)	32,722
Pension cost	11,990	17,348
Stock-based compensation	44	—
Earnings from equity method investments	(6,441)	(8,249)
Cash distribution from equity method investments	6,835	7,920
Other non-cash Items	(6,818)	(13,527)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	37,137	19,466
Inventories	(3,528)	(278)
Accounts payable, to affiliates, and accrued liabilities	67,108	5,101
Taxes accrued	21,167	(1,734)
Other assets/liabilities	15,341	(34,945)
Regulatory assets/liabilities	43,117	(58,787)
Net Cash Provided by Operating Activities	**347,648**	**199,329**
Cash Flow from Investing Activities:		
Capital expenditures	(198,531)	(195,009)
Contributions in aid of construction	881	—
Notes receivable from affiliates	(49,625)	4,400
Cash distribution from equity method investments	3,852	3,014
Net Cash Used in Investing Activities	**(243,423)**	**(187,595)**
Cash Flow from Financing Activities:		
Non-current note issuance	—	75,000
Repayments of non-current debt	—	(50,000)
Notes payable to affiliates	—	(162)
Dividends paid	(105,000)	(40,000)
Other	—	(418)
Net Cash Used in Financing Activities	**(105,000)**	**(15,580)**
Net Decrease in Cash and Cash Equivalents	**(775)**	**(3,846)**
Cash and Cash Equivalents, Beginning of Period	**775**	**4,621**
Cash and Cash Equivalents, End of Period	**$ —**	**$ 775**

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

The United Illuminating Company
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of Shares (*)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity
Balance, December 31, 2019	**100**	**$ 1**	**$ 806,230**	**$ 372,811**	**$ —**	**$ 1,179,042**
Net income	—	—	—	121,240	—	121,240
Other comprehensive loss, net of tax	—	—	—	—	(6,589)	(6,589)
Comprehensive income						114,651
Common stock dividends	—	—	—	(40,000)	—	(40,000)
Balance, December 31, 2020	**100**	**1**	**806,230**	**454,051**	**(6,589)**	**1,253,693**
Net income	—	—	—	125,377	—	125,377
Other comprehensive loss, net of tax	—	—	—	—	(3,853)	(3,853)
Comprehensive income						121,524
Stock-based compensation	—	—	429	—	—	429
Common stock dividends	—	—	—	(105,000)	—	(105,000)
Balance, December 31, 2021	**100**	**$ 1**	**$ 806,659**	**$ 474,428**	**$ (10,442)**	**$ 1,270,646**

(*) No par value.
The accompanying notes are an integral part of our financial statements.

Notes to Financial Statements

Note 1. Significant Accounting Policies

***Background and nature of operations*:** The United Illuminating Company (UI, the company, we, our, us) is a regulated operating electric public utility engaged in the purchase, transmission, distribution, and sale of electricity for residential, commercial and industrial purposes. UI is regulated as an electric distribution company by the Connecticut Public Utilities Regulatory Authority (PURA) and is also subject to regulation by the Federal Energy Regulatory Commission (FERC). UI serves approximately 342,300 customers as of December 31, 2021 in its service territory of approximately 335 square miles in southwestern Connecticut.

UI is a wholly owned subsidiary of UIL Holdings Corporation (UIL Holdings). UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

***Basis of presentation*:** The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

***Significant Accounting Policies*:** We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our financial statements:

***Revenue recognition*:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

***Regulatory accounting*:** We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

***Equity method investments*:** We account for joint ventures that do not meet consolidation criteria using the equity method. We reflect earnings (losses) recognized under the equity method in the statements of income as "Earnings (losses) from equity method investments." We recognize dividends received from joint ventures as a reduction in the carrying amount of the investment and not as dividend income. We assess and record an impairment of our equity method investments in earnings for a decline in value that we determine to be other than temporary.

***Utility plant*:** We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rate for depreciation was 2.9% of average depreciable property for 2021 and 3.3% for 2020. We amortize our capitalized software cost, which is included in other plant, using the straight line method, based on useful lives of 3 to 15 years. Capitalized software costs were approximately $290.0 million as of December 31, 2021, and $253.5 million as of December 31, 2020. Depreciation expense was $93.5 million in 2021 and $88.8 million in 2020. Amortization of capitalized software was $17.7 million in 2021 and $19.4 million in 2020.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	**Estimated useful life range (years)**		**2021**		**2020**
(Thousands)					
Distribution	6-75	$	1,950,227	$	1,791,700
Transmission	6-50		1,123,909		1,047,027
Other	6-42		411,563		496,815
Total Utility Plant in Service			**3,485,699**		**3,335,542**
Total accumulated depreciation			(958,844)		(863,071)
Total Net Utility Plant in Service			**2,526,855**		**2,472,471**
Construction work in progress			216,553		193,545
Total Utility Plant		**$**	**2,743,408**	**$**	**2,666,016**

Leases**:** We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets**:** We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

Fair value measurement**:** 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

***Derivatives and hedge accounting*:** Derivatives are recognized on our balance sheets at their fair value. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs, which we present in the same income statement line item as the earnings effect of the hedged item. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings.

***Cash and cash equivalents*:** Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in “Cash and cash equivalents.” Restricted cash represents cash legally set aside for a specified purpose as part of an agreement with a third party. Restricted cash is included in “Other non-current assets” on our balance sheets. We classify book overdrafts representing outstanding checks in excess of funds on deposit as “Accounts payable and accrued liabilities” on our balance sheets. We report changes in book overdrafts in the operating activities section of the statements of cash flows.

***Statements of cash flows*:** Supplemental disclosure of cash flow information is as follows:

		2021		2020
(Thousands)				
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	37,475	$	38,744
Income taxes paid, net	$	8,351	$	2,368

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $3.1 million in 2021 and $3.0 million in 2020. There were no accrued liabilities for utility plant additions as of December 31, 2021. Accrued liabilities for utility plant additions were $25.2 million as of December 31, 2020.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $47.5 million for 2021 and $44.1 million for 2020, and are shown net of an allowance for credit losses at December 31 of $12.3 million for 2021 and $4.4 million for 2020. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $33.3 million in 2021 and $22.9 million in 2020.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

***Variable Interest Entities*:** We have identified GenConn as a variable interest entity (VIE), which is accounted for under the equity method. We are not the primary beneficiary of GenConn, as defined in ASC 810 "Consolidation," because it shares control of all significant activities of GenConn with its joint venture, Clearway Energy, Inc. As such, GenConn is not subject to consolidation. GenConn recovers its costs through Contracts for Differences (CfDs), which are cost of service-based and have been approved by PURA. As a result, with the achievement of commercial operation by GenConn Devon and GenConn Middletown, our exposure to loss is primarily related to the potential for unrecovered GenConn operating or capital costs in a regulatory proceeding, the effect of which would be reflected on our balance sheets in the carrying value of our 50% ownership position in GenConn and in our statements of income through

"Earnings (losses) from equity method investments." Such exposure to loss cannot be determined at this time.

We have identified the selected capacity resources with which it has CfDs as VIEs and have concluded that we are not the primary beneficiary as we do not have the power to direct any of the significant activities of these capacity resources. As such, we have not consolidated the selected capacity resources. Our maximum exposure to loss through these agreements is limited to the settlement amount under the CfDs as described in Note 11. We have no requirement to absorb additional losses nor have we provided any financial or other support during the periods presented that were not previously contractually required.

We have identified the entities for which we are required to enter into long-term contracts to purchase Renewable Energy Credits (RECs) as VIEs. In assessing these contracts for VIE identification and reporting purposes, we have aggregated the contracts based on similar risk characteristics and significance to UI. We are not the primary beneficiary as we do not have the power to direct any of the significant activities of these entities. Our exposure to loss is primarily related to the purchase and resale of the RECs, but, any losses incurred are recoverable through electric rates.

***Debentures, bonds and bank borrowings*:** We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our balance sheets.

***Inventory*:** Inventory comprises materials and supplies that we use for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within "Materials and supplies."

***Government grants*:** We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in which we incur the expenses.

***Accrued removal obligations*:** We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

***Environmental remediation liability*:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2053.

***Post-employment and other employee benefits*:** We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain non-qualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over the average remaining service period or 10 years. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

***Income taxes*: ** AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, UI settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax payable balance due to AGR at December 31, 2021 was $14.0 million. The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2020 was $10.5 million.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes.

We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current on our balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in "Taxes other than income taxes" and "Taxes accrued" in our financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in our statements of income.

Uncertain tax positions are classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the income tax components of the financial statements.

***Stock-based compensation*:** Stock-based compensation represents costs related to AGR stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

***Reclassifications*:** Certain amounts reported in the financial statements in previous periods have been reclassified to conform to the current year presentation.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation; (2) exceptions to accounting for basis differences in equity method investments when there are ownership changes in foreign investments; and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers’ application of income-tax related guidance and simplify U. S. GAAP for: (1) franchise taxes that are partially based on income; (2)

transactions with a government that result in a step up in the tax basis of goodwill; (3) separate financial statements of legal entities that are not subject to tax; and (4) enacted changes in tax laws in interim periods. We adopted the amendments effective January 1, 2021, with no material effect to our results of operations, financial position, cash flows and disclosures. We are applying the amendments on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment requirement.

(b) Improvements to lessor accounting for certain leases with variable lease payments

In July 2021, the FASB issued amendments to make targeted improvements to ASC 842 for lessor's accounting for certain leases with variable lease payments, which affect lease classification. The amendments require a lessor to classify and account for a lease with variable lease payments as an operating lease if (a) the lease would have been classified as a sales-type lease or a direct financing lease and (b) the lessor would have otherwise recognized a day-one loss. The amendments are effective for fiscal years beginning after December 15, 2021, for all entities, and interim periods within those fiscal years for public business entities, with early application permitted. We have elected to early apply the amendments effective October 1, 2021, and apply the amendments prospectively to leases that commence or are modified on or after that date. Our adoption does not materially affect our results of operations, financial position and cash flows.

(c) Accounting for revenue contracts with customers acquired in a business combination

In October 2021, the FASB issued amendments related to the accounting for revenue contracts acquired in a business combination. The amendments require an entity (acquirer) to recognize and measure contract assets and contract liabilities acquired in a business combination in accordance with ASC 606, Revenue from Contracts with Customers. At the acquisition date, an acquirer should account for the related revenue contract in accordance with ASC 606 as if it had originated the contracts. Generally, this should result in an acquirer recognizing and measuring the acquired contract assets and contract liabilities consistent with how they were recognized and measured in the acquiree's financial statements. The amendments also provide certain practical expedients for acquirers when recognizing and measuring acquired contract assets and contract liabilities from revenue contracts in a business combination. For public business entities, the amendments are effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The amendments should be applied prospectively to business combinations occurring on or after the effective date of the amendments. Early adoption is permitted. We have elected to early apply the amendments effective October 1, 2021. Our adoption did not materially affect our results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2021, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the "discounting transition," may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments were effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Our prospective adoption of ASC 848 on January 1, 2022 will not materially affect our results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

In November 2021, the FASB issued amendments that apply to business entities (all entities except specified not-for-profit entities and employee benefit plans) that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance (such as a grant model within International Accounting Standards 20 Accounting for Government Grants and Disclosure of Government Assistance, or ASC Subtopic 958-605, Not-For-Profit Entities—Revenue Recognition). Government assistance can include tax credits (excluding transactions within the scope of Topic 740, Income Taxes), cash grants, grants of other assets, and project grants. Often, government assistance is provided to an entity for a particular purpose, and the entity promises to take specific actions. Transactions with a government, as used in ASC 832, Government Assistance, include assistance administered by domestic, foreign, local (city, town, county, municipal), regional (state, provincial, territorial), and national (federal) governments and entities related to those governments. The amendments require annual disclosures in notes to financial statements about transactions with a government as follows: (1) information about the nature of the transactions and the related accounting policy used to account for the transactions, (2) the line items on the balance sheet and income statement affected by the transactions, and the amounts applicable to each financial statement line item, and (3) significant terms and conditions of the transactions, including commitments and contingencies. For entities within scope the amendments are effective for annual periods beginning after December 15, 2021, with early application permitted. The amendments are to be applied either (1) prospectively to transactions within the scope of the amendments that are reflected in financial statements at the date of initial application and new transactions that are entered into after the date of initial application or (2) retrospectively to those transactions. Our adoption of the amendments on January 1, 2022 will not materially affect our disclosures.

***Use of estimates and assumptions*:** The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanism; (11) environmental remediation liabilities; and (12) pension and other postretirement employee benefits. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our financial statements in future reporting periods.

***Union collective bargaining agreements*:** Approximately 60.4% of our employees are covered by a collective bargaining agreement. Agreements expiring in the coming year apply to approximately 9.4% of our union employees.

Note 2. Industry Regulation

Rates

Utilities are entitled by Connecticut statutes to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital, and to maintain their financial integrity, while also protecting relevant public interests.

UI's approved three-year distribution rate schedules became effective January 1, 2017 and include, among other things, annual tariff increases and an ROE of 9.10% based on a 50.00% equity ratio, continuation of UI's existing earnings sharing mechanism (ESM) pursuant to which UI and its customers share on a 50/50 basis all distribution earnings above the allowed ROE in a calendar year, continuation of the existing decoupling mechanism, and the continuation of a requested storm reserve. Any dollars due to customers from the ESM continue to be first applied against any storm regulatory asset balance (if one exists at that time) or refunded to customers through a bill credit if such storm regulatory asset balance does not exist.

Connecticut Energy Legislation

On October 7, 2020, the Governor of Connecticut signed into law an energy bill that, among other things, instructs PURA to revise the rate-making structure in Connecticut to adopt performance-based rates for each electric distribution company, increases the maximum civil penalties assessable for failures in emergency preparedness, and provides for certain penalties and reimbursements to customers after storm outages greater than 96 hours and extends rate case timelines.

Pursuant to the legislation, on October 30, 2020, PURA re-opened a docket related to new rate designs and review, expanding the scope to consider (a) the implementation of an interim rate decrease; (b) low-income rates; and (c) economic development rates. Separately, UI was due to make its annual rate adjustment mechanism, or RAM, filing on March 8, 2021 for the approval of its RAM Rate Components reconciliations: Generation Services Charges, By-passable Federally Mandated Congestion Costs, System Benefits Charge, Transmission Adjustment Charge and RDM.

On March 9, 2021, UI, jointly with the Office of the CT Attorney General, the Office of CT Consumer Counsel, DEEP and PURA's Office of Education, Outreach, and Enforcement entered into a settlement agreement and filed a motion to approve the settlement agreement, which addressed issues in both dockets.

In an order dated June 23, 2021, PURA approved the as amended settlement agreement in its entirety and it was executed by the parties. The settlement agreement includes a contribution by UI of $5 million and provides customers rate credits of $50 million while allowing UI to collect $52 million in RAM, all over a 22-month period ending April 2023 and also includes a distribution base rate freeze through April 2023.

Pursuant to the legislation, PURA opened a docket to consider the implementation of the associated customer compensation and reimbursement provisions in emergency events where customers were without power for more than 96 consecutive hours. On June 30, 2021, PURA issued a final decision implementing the legislative mandate to create a program pursuant to which residential customers will receive $25 for each day without power after 96 hours and also receive reimbursement of $250 for spoiled food and medicine. The decision emphasizes that no costs incurred in connection with this program are recoverable from customers. The Company is reviewing the requirements of this program and evaluating next steps.

Power Supply Arrangements

Under Connecticut law, UI's retail electricity customers can choose their electricity supplier while UI remains their electric distribution company. UI purchases power for those of its customers under standard service rates who do not choose an alternative retail electric supplier and have a maximum demand of less than 500 kilowatts, as well as its customers under supplier of last resort service who are not eligible for standard service rates and do not choose to purchase electric generation service from an alternate retail electric supplier. The cost of the purchased power is a "pass-through" to those customers through the General Services Charge (GSC) charge on their bills.

UI must procure the power to serve its standard service load pursuant to a procurement plan approved by PURA. Under the procurement plan, UI procures wholesale power for its standard service customers on a full requirements basis pursuant to contracts with a maximum duration of 12 months, with the delivery of such wholesale power to commence no later than one year from the applicable bid day.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2022, 80% of the second half of 2022, and 20% of its standard load for the first half of

2023. Supplier of last resort service is procured on a quarterly basis and UI has wholesale power supply agreement in place for the first and second quarters of 2022. However, from time to time there are no bidders in the procurement process for supplier of last resort service and, in such cases, UI manages the load directly.

UI determined that its contracts for standard service and supplier of last resort service are derivatives under ASC 815 "Derivatives and Hedging" and elected the "normal purchase, normal sale" exception under ASC 815 "Derivatives and Hedging." UI regularly assesses the accounting treatment for its power supply contracts. These wholesale power supply agreements contain default provisions that include required performance assurance, including certain collateral obligations, in the event that UI's credit rating on senior debt were to fall below investment grade. If such an event had occurred as of December 31, 2021, UI would have had to post an aggregate of approximately $18.7 million in collateral.

New Renewable Source Generation

Under Connecticut Public Act (PA) 11-80, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I RECs from renewable generators located on customer premises. Under this program, UI was initially required to enter into contracts totaling approximately $200 million in commitments over an approximate 21-year period. The obligations were initially expected to phase in over a six-year solicitation period and peak at an annual commitment level of about $14 million per year after all selected projects are online. PA 17-144, PA 18-50 and PA 19-35 extended the original six-year solicitation period of the program by adding seventh, eighth, ninth, and tenth years, and increased the original funding level of this program by adding up to $64 million in additional commitments by UI. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

In 2019, UI entered into PPAs with 11 projects, totaling approximately 12 million MWh, pursuant to state law with developers and operators of nuclear, offshore wind, and solar generation pursuant that provides that the net costs of the PPAs are recoverable through electric rates. Throughout 2019 and 2020, PURA approved the PPAs, and approved UI's use of the non-bypassable federally mandated congestion charge for all customers to recover the net costs of the PPAs.

In May, 2020 Pursuant to Connecticut Act Concerning the Procurement of Energy Derived From Offshore Wind, UI entered into a PPA with Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project, and that PPA provides that the net costs of the PPAs are recoverable through electric rates. On August 19, 2020, PURA approved the PPA, and approved UI's use of the non-bypassable federally mandated congestion charge for all customers to recover the net costs of the PPA.

Revenues are recorded gross from contracts with customers when UI is a principal if it controls a promised good or service before transferring that good or service to the customer. Revenues are recorded net of expenses and regulatory deferrals from contracts with customers when UI is an agent if it arranges for another entity to provide the goods or services.

Transmission

PURA decisions do not affect the revenue requirements determination for UI's transmission business, including the applicable ROE. UI's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets. For 2021, UI's overall allowed weighted-average ROE for its transmission business was 11.25%.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judgement procedures. Pursuant to section 206 of the FPA, the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners (PTOs), including UI. The FERC also found that the current Regional Network Service (RNS) and Local Network Service (LNS) formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. On June 15, 2020, the PTOs submitted an uncontested formula rate settlement. The FERC approved the uncontested formula rate settlement on December 28, 2020 which makes the formula rate tariff sheets effective on January 1, 2022.

On September 30, 2011, the Massachusetts Attorney General, DPU, PURA, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint with the FERC, pursuant to sections 206 and 306 of the Federal Power Act, against several NETOs claiming that the approved base ROE of 11.14% used by NETOs in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).

On October 16, 2014, the FERC issued its decision in Complaint I setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners.

UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. UI's total reserve associated with Complaints II and III is $7.6 million as of December 31, 2021, which has not changed since December 31, 2020, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $4.3 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order).

Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing of this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. On November 19, 2020, FERC issued an order addressing arguments raised on rehearing of its May 21, 2020 order, making minor adjustments to certain typographical errors with regard to some of the case inputs it included in its Risk Premium model analysis. However, those minor adjustments did not affect the outcome of the case, leaving the 10.02% ROE established by the May 21, 2020 order in place. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETO's submitted an amici curia brief in support of the MISO transmission owners' on March 17, 2021. We cannot predict the outcome of these proceedings, including the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for our pending four Complaints.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after 3 years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate UI would have an approximately $2 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

Equity Investment in Peaking Generation

UI is a party to a joint venture with Clearway Energy, Inc., a subsidiary of Global Infrastructure Partners (GIP), pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly-owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown). The two peaking generation plants are both participating in the ISO-New England markets.

GenConn filed its annual revenue requirements request with PURA on June 15, 2021, seeking approval of its 2022 revenue requirements for the period commencing January 1, 2022 for both the GenConn Devon and GenConn Middletown facilities and totaling $55.8 million. A final decision was received on December 08, 2021, approving 2022 revenue requirements of $44.4 million for GenConn ($19.3 million for GenConn Devon, and $25.1 million for GenConn Middletown). Additionally, GenConn was granted a 9.85% Return on Equity (ROE) for 2022. PURA disallowed $2.9 million from the original 2021 revenue requirements associated with interest expense associated with GenConn's debt, $0.1 million associated with 2013 refinancing amortization, $6.1 million associated with its equity return and $2.3 million associated with the resulting income tax, totaling $11.4 million. On January 21, 2022, GenConn filed an appeal with the CT Superior Court, appealing PURA's disallowance of the $11.4 million.

GenConn filed its annual revenue requirements request with PURA on June 12, 2020, seeking approval of its 2021 revenue requirements for the period commencing January 1, 2021 for both the GenConn Devon and GenConn Middletown facilities. A final decision was received on December 23, 2020, approving 2021 revenue requirements of $49.4 million for GenConn ($22.0 million for GenConn Devon, and $27.4 million for GenConn Middletown). Additionally, GenConn was granted a 9.85% Return on Equity (ROE) for 2021. PURA disallowed $3.3 million from the original 2021 revenue requirements request which includes a disallowance of $2.9 million of interest expense associated with GenConn's debt, and $0.4 million related to a proposed expense project to paint Exhaust Stacks at GenConn Devon. On February 4, 2021, GenConn filed an appeal with the CT Superior Court, appealing PURA's disallowance of the $2.9 million interest expense. The appeal remains pending.

PURA had approved revenue requirements for the period from January 1, 2020 through December 31, 2020, however, GenConn filed to reopen the related docket with PURA on April 3, 2020, for the purpose of resetting 2020 revenue requirements after a recalculation of excess deferred income taxes. GenConn received a final decision from PURA on December 23, 2020 approving $1.2 million of the additional $2.1 million requested for 2020 revenue requirements. The $0.9 million difference is due to an acceleration of $0.6 million related to Excess Accumulated Deferred Income Tax (ADIT) associated with Intangible Plant that otherwise would have been refunded over a longer period of time, and $0.3 million is related to actual tangible plant timing differences.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates.

PURA instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state and rendered a final decision on January 23, 2019. PURA directed UI to establish a regulatory liability in the amount of the income tax expense to be returned to customers and propose a method of returning such amount to customers in its next rate case filing. On June 28, 2021, PURA approved a multi-docket settlement proposal that required UI to flow accumulated Tax Act savings back to customers over a 22-month period, commencing on July 1, 2021 through April 30, 2023.

On December 22, 2021, the FERC issued an order finding that the New England Transmission Owners (NETOs) Regional Network Service proposed revisions partially comply with the requirements of Order 864 and directed the NETOs to submit a further compliance filing within 60 days of the date of the order. The compliance is effective January 27, 2020, consistent with Order 864 and January 1, 2022, to reflect the fact that the NETOs existing transmission formula rates under the ISO-NE Tariff will be replaced by a settled formula rate effective January 1, 2022.

PURA Investigation of the Preparation for and Response to the Tropical Storm Isaias and Connecticut Storm Reimbursement Legislation

On August 6, 2020, the PURA opened a docket to investigate the preparation for and response to Tropical Storm Isaias by the electric distribution companies in Connecticut including UI. Following hearings and the submission of testimony, PURA issued a final decision on April 15, 2021, finding that UI “generally met standards of acceptable performance in its preparation and response to Tropical Storm Isaias," subject to certain exceptions noted in the decision, but ordered a 15-basis point reduction to UI’s ROE in its next rate case to incentivize better performance and indicated that penalties could be forthcoming in the penalty phase of the proceedings. On June 11, 2021, UI filed an appeal of PURA's decision with the Connecticut Superior Court.

On May 6, 2021, in connection with its findings in the Storm Isaias Docket, PURA issued a Notice of Violation to UI for allegedly failing to comply with standards of acceptable performance in emergency preparation or restoration of service in an emergency and with orders of the Authority, and for violations of accident reporting requirements. PURA assessed a civil penalty in the total amount of $2 million. PURA held a hearing on this matter and, in an order dated July 14, 2021, reduced the civil penalty to approximately $1 million. UI filed an appeal of PURA’s decision with the Connecticut Superior Court. This appeal and the appeal of PURA’s decision on the Tropical Storm Isaias docket have been consolidated. We cannot predict the outcome of these appeals.

Minimum Equity Requirements for Regulated Subsidiaries

Pursuant to agreements with PURA, UI is restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, UI is prohibited from paying dividends to their parent if the utility’s credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility’s credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $300.9 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and non-current regulatory assets consisted of:

As of December 31,	2021	2020
(Thousands)		
Current		
Contracts for differences	$ 14,136	$ 13,378
Deferred transmission expense	6,311	25,594
Excess generation service charge	4,960	—
Non-bypassable charges	764	—
Revenue decoupling mechanism	16,767	2,663
Storm costs	—	2,000
Unamortized losses on reacquired debt	499	780
Other	881	—
Total current regulatory assets	**44,318**	**44,415**
Non-current		
Contracts for differences	44,536	55,806
COVID-19 cost recovery	10,416	918
Deferred transmission expense	7,196	—
Environmental remediation costs	6,311	6,000
Excess generation service charge	6,196	6,052
Non-bypassable charges	3,836	15,496
Pension and other postretirement benefit plans	125,151	169,082
Pension and other postretirement benefits cost deferrals	13,755	11,185
Revenue decoupling mechanism	191	15,329
Storm costs	23,135	13,793
Unamortized losses on reacquired debt	4,956	5,007
Unfunded future income taxes	110,501	103,103
Other	14,014	10,155
Total non-current regulatory assets	**$ 370,194**	**$ 411,926**

Contracts for differences represent the deferral of unrealized gains and losses on contracts for differences derivative contracts. The balance fluctuates based upon quarterly market analysis performed on the related derivatives. The amounts, which do not earn a return, are fully offset by a corresponding derivative asset/liability.

COVID-19 cost recovery represents deferred COVID-19-related costs in the state of Connecticut based on the order issued by PURA on April 29, 2020, requiring utilities to track COVID-19-related expenses and lost revenue and create a regulatory asset.

Deferred transmission expense represents deferred transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

Environmental remediation costs includes spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Excess generation service charge represents deferred generation-related and non-bypassable federally mandated congestion costs or revenues for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Non-bypassable charges represent non-bypassable federally mandated congestion costs or revenues for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses.

Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates for certain of our regulated utilities. The recovery of these amounts will be determined in future proceedings.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. UI is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. A portion of this balance is amortized through current rates, and the remaining portion will be determined through future rate cases.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment and are the offset to the unfunded future deferred income tax liability recorded. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes items such as deferred loss on sale of non-utility property.

Current and non-current regulatory liabilities consisted of:

As of December 31,	2021	2020
(Thousands)		
Current		
2017 Tax Act	$ 26,274	$ —
Accumulated deferred investment tax credits	730	730
Conservation and load management	(156)	9,875
Earnings sharing provision	(277)	4,718
Middletown/Norwalk local transmission network service collections	573	573
Non-bypassable charges	5,165	—
System benefit charge	12,049	534
Other	755	—
Total current regulatory liabilities	**45,113**	**16,430**
Non-current		
2017 Tax Act	225,742	265,642
Accrued removal obligations	72,165	67,138
Accumulated deferred investment tax credits	10,628	11,555
Middletown/Norwalk local transmission network service collections	16,242	16,816
Pension and other postretirement benefit plans	15,538	13,950
Rate refund - FERC ROE proceeding	7,600	7,234
Other	4,106	3,139
Total non-current regulatory liabilities	**$ 352,021**	**$ 385,474**

2017 Tax Act represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers. UI will be returning the accumulated income tax expense to customers over the 22-month period from July 1, 2021 through April 30, 2023.

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Accumulated deferred investment tax credits represent investment tax credits related to plant investments that are deferred when earned and amortized over the estimated lives of the related assets.

Earning sharing provisions represents the annual earnings over the earnings sharing threshold. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

Middletown/Norwalk local transmission network service collections represents allowance for funds used during construction of the Middletown/Norwalk transmission line, which is being amortized over the useful life of the project.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses.

Rate refund - FERC ROE proceeding represents the reserve associated with the FERC proceeding around the base return on equity (ROE) reflected in ISO New England, Inc.'s (ISO-NE) open access transmission tariff (OATT).

Systems benefit charge represents various costs or revenues as defined by Connecticut General Statute 16-2451 deferred for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Other includes items such as deferral of CAM gross earnings tax expense collected in base distribution rates for periods subsequent to January 1, 2020.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

UI derives its revenue primarily from tariff-based sales of electricity service to customers in its Connecticut territory with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the electricity delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity.

Tariff-based sales are subject to PURA, which determines prices and other terms of service through the ratemaking process. Customers have the option to obtain the electricity directly from UI or from another supplier. For customers that receive their electricity from another supplier, UI acts as an agent and delivers the electricity by that supplier. Revenue in those cases is only for providing the service of delivery of the electricity.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by an independent entity, ISO-New England, Inc.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as UI delivers or sells the electricity or provides the transmission service.

UI records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between UI and their regulators. UI ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, and annual revenue requirement reconciliations.

UI also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

Revenues disaggregated by major source for the years ended December 31, 2021 and 2020 are as follows:

Years Ended December 31,	**2021**	**2020**
(Thousands)		
Regulated operations – electricity	$ 1,020,219	$ 988,727
Other (a)	5,633	5,853
Revenue from contracts with customers	**1,025,852**	**994,580**
Leasing revenue	2,942	1,294
Alternative revenue programs	41,937	49,438
Other revenue	174	1,534
Total operating revenues	**$ 1,070,905**	**$ 1,046,846**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	**2021**	**2020**
(Thousands)		
Current		
Federal	$ 26,605	$ 32
State	4,529	(387)
Current taxes charged to expense (benefit)	**31,134**	**(355)**
Deferred		
Federal	(5,968)	27,336
State	359	5,386
Deferred taxes charged to expense	**(5,609)**	**32,722**
Investment tax credits	(730)	(730)
Total Income Tax Expense	**$ 24,795**	**$ 31,637**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	2021	2020
(Thousands)		
Tax expense at federal statutory rate	$ 31,536	$ 32,104
Depreciation/amortization and other plant differences not normalized	(2,073)	(3,075)
State taxes net of federal benefit	3,862	3,950
Investment tax credit amortization	(730)	(730)
Excess ADIT giveback	(6,906)	—
Other, net	(894)	(612)
Total Income Tax Expense	**$ 24,795**	**$ 31,637**

Income tax expense for the year ended December 31, 2021 was $6.7 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Depreciation, amortization and other plant differences not normalized partially offset by state taxes. This resulted in an effective tax rate of 16.5%. Income tax expense for the year ended December 31, 2020 was $0.5 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Depreciation, amortization and other plant differences not normalized partially offset by state taxes. This resulted in an effective tax rate of 20.7%

As part of a settlement agreement approved by PURA, UI began refunding previously deferred Distribution Excess ADITS, commencing July 1, 2021. In 2021, UI began refunding previously deferred Transmission Excess ADITS as determined by the FERC.

Deferred tax assets and liabilities as of December 31, 2021 and 2020 consisted of:

December 31,	2021	2020
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 416,992	$ 400,863
Unfunded future income taxes	35,969	33,822
Federal and state tax credits	(16,006)	(15,943)
Investment in GenConn	31,369	32,124
Postretirement benefits	(12,111)	(13,941)
Regulatory liability due to "Tax Cuts and Jobs Act"	(67,864)	(71,524)
Other	1,201	14,258
Total Non-current Deferred Income Tax Liabilities	**$ 389,550**	**$ 379,659**
Deferred tax assets	$ 95,981	$ 101,408
Deferred tax liabilities	485,531	481,067
Net Accumulated Deferred Income Tax Liabilities	**$ 389,550**	**$ 379,659**

As of December 31, 2021, UI had $5.8 million of state tax credit carry forwards that will begin to expire in 2025. As of December 31, 2020, UI had $6.0 million of state tax credit carry forwards with an offset of $0.6 million valuation allowance.

Uncertain tax positions are classified as non-current unless expected to be paid within one year. We net our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income. As of December 31, 2021 and 2020, UI did not have any gross income tax reserves for uncertain tax positions.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2021 and 2020.

Note 6. Non-current Debt

Long-term debt as of December 31, 2021 and 2020 consisted of:

As of December 31,		2021		2020	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured notes	2022 - 2049	$ 891,960	2.02% - 6.51%	$ 891,960	2.02% - 6.51%
Unamortized debt issuance costs and discount		(4,752)		(5,033)	
Total Debt		**887,208**		**886,927**	
Less: debt due within one year, included in current liabilities		162,137		—	
Total Non-current Debt		**$ 725,071**		**$ 886,927**	

On December 1, 2020, UI issued $75 million aggregate principal amount of unsecured notes maturing in 2030 at an interest rate of 2.02%.

Long-term debt, including sinking fund obligations, due during the next five years consist of:

(Thousands) 2022	2023	2024	2025	2026	Total
$ 162,137	$ 139,460	$ —	$ 100,000	$ —	$ 401,597

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2021 and 2020.

Note 7. Bank Loans and Other Borrowings

UI had no short-term debt outstanding as of December 31, 2021 and December 31, 2020. UI funds short-term liquidity needs through an agreement among Avangrid’s regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility), and a bank provided credit facility to which UI is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. UI has a lending/borrowing limit of $100 million under this agreement. UI had no debt outstanding under this agreement at December 31, 2021 and December 31, 2020.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. UI had no debt outstanding under this agreement at December 31, 2021 and December 31, 2020.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation (“NYSEG”), Rochester Gas and Electric Corporation (“RG&E”), Central Maine Power Company (“CMP”), The United Illuminating Company (“UI”), Connecticut Natural Gas Corporation (“CNG”), The Southern Connecticut Gas Company (“SCG”) and The Berkshire Gas Company (“BGC”)) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23 2021, the AGR Credit Facility was amended to increase AGR’s maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. UI had no debt outstanding under this agreement at December 31, 2021 and December 31, 2020.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.41 to 1.00 at December 31, 2021. We are not in default as of December 31, 2021.

Note 8. Preferred Stock

At December 31, 2021, UI had 1,119,612 shares of $100 par value preferred stock, 2,400,000 shares of $25 par value preferred stock, and 5,000,000 shares of $25 par value preference stock authorized but unissued.

Note 9. Leases

We have operating leases for land, office buildings, facilities, and certain equipment. We do not have any finance leases. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 42 years, some of which may include options to extend the leases for up to 40 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

For the Years Ended December 31,	2021	2020
(Thousands)		
Lease cost		
Operating lease cost	$ 2,795	$ 2,652
Short-term lease cost	69	—
Variable lease cost	751	—
Intercompany	122	—
Total lease cost	**$ 3,737**	**$ 2,652**

Balance sheet and other information for the years ended December 31, 2021 and 2020 was as follows:

As of December 31,	2021	2020
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 11,339	$ 10,041
Operating lease liabilities, current	1,002	1,510
Operating lease liabilities, long-term	14,644	12,806
Total operating lease liabilities	$ 15,646	$ 14,316
Weighted-average Remaining Lease Term (years)		
Operating leases	21.52	22.63
Weighted-average Discount Rate		
Operating leases	3.32%	3.91%

For the years ended December 31, 2021 and 2020, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,	2021	2020
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,728	$ 1,650
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 2,731	$ —

As of December 31, 2021, maturities of lease liabilities were as follows:

(Thousands)		Operating Leases
Year ending December 31,		
2022	$	1,259
2023		933
2024		894
2025		809
2026		828
Thereafter		19,414
Total lease payments		**24,137**
Less: imputed interest		(8,491)
Total	**$**	**15,646**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric service.

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then owners of a former generation site on the Mill River in New Haven (English Station) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut related to environmental remediation at the English Station site. This proceeding was stayed in 2014 pending resolutions of other proceedings before the DEEP concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party.

In December 2013, Evergreen Power and Asnat filed a subsequent lawsuit related to the English Station site. On April 16, 2018, the plaintiffs filed a revised complaint alleging fraud and unjust enrichment against UIL and UI and adding former UIL officers as named defendants alleging fraud. On February 21, 2019, the court granted our Motion to Strike with respect to all counts except for the count against UI for unjust enrichment. The counts stricken include all counts against the individual defendants as well as against UIL. The plaintiffs have appealed the court's decision to strike and oral arguments have taken place. On May 4, 2021, the Appeals Court affirmed the court's decision striking the counts. The plaintiffs filed a petition to appeal to the Connecticut Supreme Court, which was denied, leaving only the claim against UI for unjust enrichment. We cannot predict the outcome of this matter.

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. Status reports are periodically filed with DEEP.

On August 4, 2016, DEEP issued a partial consent order (the consent order), that, subject to its terms and conditions, requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the consent order, to the extent that the cost of this investigation and remediation is less than $30 million, UI will remit to the State of Connecticut the difference between such cost and $30 million to be used for a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut and the Commissioner of DEEP. UI is obligated to comply with the terms of the consent order even if the cost of such compliance exceeds $30 million. Under the terms of the consent order, the state will discuss options with UI on recovering or funding any cost above $30 million such as through public funding or recovery from third parties; however, it is not bound to agree to or support any means of recovery or funding. UI has continued its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order.

As of both December 31, 2021 and December 31, 2020, the amount reserved related to English Station was $21.7 million. We cannot predict the outcome of this matter.

Other

In May 2019, UI obtained an updated remediation evaluation of the property adjacent to the New Haven Harbor Generating Station. As a result, UI recorded an additional $6.0 million reserve in June 2019, the minimum of the range of remediation estimates. As of December 31, 2021 and December 31, 2020, the amount reserved for this property was $7.7 million and $7.8 million, respectively.

UI also holds a reserve for remediation of 801 Bridgeport Ave, the site of a former operations center. The amount reserved for this site was $0.4 million and $0.5 million as of December 31, 2021 and December 31, 2020, respectively.

Note 11. Accounting for Derivative Instruments and Hedging Activities

Our operating and financing activities are exposed to certain risks, which are managed by using derivative instruments. All derivative instruments are recognized as either assets or liabilities at fair value on our balance sheets in accordance with the accounting requirements concerning derivative instruments and hedging activities.

Derivatives not designated as hedging instruments

Pursuant to Connecticut's 2005 Energy Independence Act, PURA solicited bids to create new or incremental capacity resources in order to reduce federally mandated congestion charges, and selected four new capacity resources. To facilitate the transactions between the selected capacity resources and Connecticut electric customers, and provide the commitment necessary for owners of these resources to obtain necessary financing, PURA required that UI and The Connecticut Light and Power Company (CL&P) execute long-term contracts with the selected resources. In August 2007, PURA approved four CfDs, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. UI executed two of the contracts and CL&P executed the other two contracts. The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement between UI and CL&P pursuant to which approximately 20% of the cost or benefit is borne by or allocated to UI customers and approximately 80% is borne by or allocated to CL&P customers.

PURA has determined that costs associated with these CfDs will be fully recoverable by UI and CL&P through electric rates, and in accordance with ASC 980 "Regulated Operations," UI has deferred recognition of costs (a regulatory asset) or obligations (a regulatory liability). The CfDs are marked-to-market in accordance with ASC 815 “Derivatives and Hedging.” For those CfDs signed by CL&P, UI records its approximate 20% portion pursuant to the cost-sharing agreement noted above. As of December 31, 2021, UI has recorded a gross derivative asset of $1.7 million ($0 of which is related to UI’s portion of the CfD signed by CL&P), a regulatory asset of $58.7 million, a gross derivative liability of $60.4 million ($58.2 million of which is related to UI’s portion of the CfD signed by CL&P), and a regulatory liability of $0. As of December 31, 2020, UI had recorded a gross derivative asset of $2.0 million ($0 of which is related to UI’s portion of the CfD signed by CL&P), a regulatory asset of $69.2 million, a gross derivative liability of $71.2 million ($68.7 million of which is related to UI’s portion of the CfD signed by CL&P), and a regulatory liability of $0.

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets, for the years ended December 31, 2021 and 2020, respectively, were as follows:

	Years Ended December 31, 2021	2020
(Thousands)		
Derivative assets	$ (327)	$ —
Derivative liabilities	$ 10,839	$ 3,502

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on Other Comprehensive Income (OCI) and income for the years ended December 31, 2021 and 2020, respectively, consisted of:

Year Ended December 31,	Loss Recognized in OCI on Derivatives	Location of Loss Reclassified From Accumulated OCI into Income	Loss Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2021				
Foreign exchange contracts	$ (23)	Operations and maintenance	$ —	$ 390,980
Total	**$ (23)**		**$ —**	

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,029 million as of December 31, 2021 and $1,100 million as of December 31, 2020. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2021 and December 31, 2020, consisted of:

As of December 31, 2021	Level 1	Level 2	Level 3	Total
(Thousands)				
Derivative assets				
Contracts for differences	$ —	$ —	$ 1,711	$ 1,711
Equity investments with readily determinable fair values				
Supplemental retirement benefit trust life insurance policies	—	15,431	—	15,431
Total	**$ —**	**$ 15,431**	**$ 1,711**	**$ 17,142**
Derivative liabilities				
Contracts for differences	$ —	$ —	$ (60,383)	$ (60,383)
Foreign exchange contracts	—	(23)	—	(23)
Total	**$ —**	**$ (23)**	**$ (60,383)**	**$ (60,406)**

As of December 31, 2020	Level 1	Level 2	Level 3	Total
(Thousands)				
Derivative assets				
Contracts for differences	$ —	$ —	$ 2,038	$ 2,038
Equity investments with readily determinable fair values				
Supplemental retirement benefit trust life insurance policies	—	14,299	—	14,299
Total	**$ —**	**$ 14,299**	**$ 2,038**	**$ 16,337**
Derivative liabilities				
Contracts for differences	$ —	$ —	$ (71,222)	$ (71,222)
Total	**$ —**	**$ —**	**$ (71,222)**	**$ (71,222)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2021 and 2020. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We determine the fair value of our derivative assets and liabilities and non-current equity investments utilizing market approach valuation techniques:

- UI enters into CfDs, which are marked-to-market based on a probability-based expected cash flow analysis that is discounted at risk-free interest rates and an adjustment for non-performance risk using credit default swap rates. We include the fair value measurement for these contracts in Level 3 (Refer to Note 11 for further discussion of CfDs).
- We measure the fair value of the supplemental retirement benefit life insurance trust based on quoted prices in the active markets for the various funds within which the assets are held and include the measurement in Level 2.
- We determine the fair value of our foreign currency exchange derivative instruments based on current exchange rates compared to the rates at inception of the hedge. We include the fair value measurement for these contracts in Level 2.

The determination of fair value of the CfDs was based on a probability-based expected cash flow analysis that was discounted at risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that extends over the term of the contracts. We believe this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs. Additionally, on a quarterly basis, we perform analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. Significant isolated changes in the risk of non-performance, the discount rate or the contract term pricing would result in an inverse change in the fair value of the CfDs. Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at December 31, 2021	Range at December 31, 2020
Risk of non-performance	0.39% - 0.51%	0.50% - 0.51%
Discount rate	0.97% - 1.26%	0.17% - 0.36%
Forward pricing ($ per MW)	$2.00 - $4.80	$2.00 - $5.30

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2021 and 2020, respectively, is as follows:

Years Ended December 31,		2021		2020
(Thousands)				
Beginning balance	$	(69,184)	$	(72,686)
Unrealized gains/(losses), net		10,512		3,502
Ending balance	**$**	**(58,672)**	**$**	**(69,184)**

Note 13. Postretirement and Similar Obligations

The UI pension plan provides benefits under a traditional defined benefit formula and was closed to newly-hired employees in 2005. The plan was amended, effective as of the close of business on December 31, 2020, to freeze benefit accruals for UI Collectively Bargained Group 1 participants and to permit in-service distributions to UI Collectively Bargained Group 1 participants who are at least age 60. The plan was remeasured as of December 9, 2020 as a result of this amendment. On March 31, 2022, the Board approved to freeze benefit accruals for the non-union participants of the UI pension plan, with an effective date of June 30, 2022.

UI employees are eligible to participate in the UIL Holdings Corporation 401(k) Employee Stock Ownership Plan. Employees may defer a portion of their compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expense totaled approximately $6.6 million for 2021 and $5.5 million for 2020.

We provide other postretirement benefits, consisting principally of health care and life insurance benefits, for retired employees and their dependents. The healthcare plans are contributory and participants’ contributions are adjusted annually. For Medicare eligible non-union retirees, UI provides a subsidy through a Health Reimbursement Account (HRA) for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Non-Qualified Retirement Benefit Plans

We sponsor various unfunded non-qualified pension plans for certain current employees, former employees, and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $14.0 million and $9.5 million at December 31, 2021 and 2020, respectively. On March 31, 2022, the Board approved to freeze benefit accruals for the non-union participants of the UI supplemental executive retirement plan, with an effective date of June 30, 2022.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 604,221**	**$ 612,284**	**$ 64,178**	**$ 59,066**
Service cost	3,730	5,248	621	651
Interest cost	15,031	18,795	1,424	1,826
Plan amendments	—	7,382	—	—
Actuarial (gain) loss	(17,813)	18,873	1,552	7,955
Curtailments	—	(18,490)	—	—
Benefits paid	(43,235)	(39,871)	(5,859)	(5,320)
Benefit obligation as of December 31,	**$ 561,934**	**$ 604,221**	**$ 61,916**	**$ 64,178**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 429,238**	**$ 383,517**	**$ 34,257**	**$ 27,006**
Actual return on plan assets	37,169	52,862	5,173	10,425
Employer contributions	—	32,730	4,662	2,146
Benefits paid	(43,235)	(39,871)	(5,859)	(5,320)
Fair value of plan assets at December 31,	**$ 423,172**	**$ 429,238**	**$ 38,233**	**$ 34,257**
Funded status at December 31,	**$ (138,762)**	**$ (174,983)**	**$ (23,683)**	**$ (29,921)**

During 2021, the pension benefit obligation had an actuarial gain of $17.8 million, primarily due to a $29.5 million gain from increases in discount rates, offset by a $9.8 million loss from demographic and other experience and a $1.9 million loss from changes in mortality. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2020, the pension benefit obligation had an actuarial loss of $18.9 million, primarily due to a $47.2 million loss from decreases in discount rates, offset by gains due to changes in mortality, demographic and other assumptions of $4.8 million, $10.6 million and $12.1 million, respectively. The only significant plan change in 2020 was an agreement to freeze the union pension plan. During 2020, the postretirement benefit obligation had an actuarial loss of $8.0 million.

Amounts recognized as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
(Thousands)				
Non-current liabilities	$ (138,762)	$ (174,983)	$ (23,683)	$ (29,921)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2021 and 2020 consisted of:

Years Ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net loss (gain)	$ 119,004	$ 166,052	$ (7,356)	$ (6,509)
Prior service cost (credit)	$ 6,147	$ 7,309	$ (2,593)	$ (4,130)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $538.9 million and $575.1 million as of December 31, 2021 and 2020, respectively. Our postretirement benefits were partially funded at December 31, 2021 and 2020.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2021 and 2020. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,	2021	2020
(Thousands)		
Projected benefit obligation	$ 561,934	$ 604,221
Accumulated benefit obligation	$ 538,930	$ 575,083
Fair value of plan assets	$ 423,172	$ 429,238

As of December 31, 2021 and 2020, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2021 and 2020 consisted of:

For the years ended December 31,	Pension Benefits 2021	Pension Benefits 2020	Postretirement Benefits 2021	Postretirement Benefits 2020
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 3,730	$ 5,248	$ 621	$ 651
Interest cost	15,031	18,795	1,424	1,826
Expected return on plan assets	(29,394)	(28,451)	(1,953)	(1,688)
Amortization of prior service cost (benefit)	1,163	73	(1,537)	(1,537)
Amortization of net loss (gain)	21,460	23,116	(821)	(798)
Net Periodic Benefit Cost	**$ 11,990**	**$ 18,781**	**$ (2,266)**	**$ (1,546)**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Curtailments	$ —	$ (18,489)	$ —	$ —
Net gain	(25,588)	(5,538)	(1,668)	(784)
Amortization of net (loss) gain	(21,460)	(23,116)	821	798
Current year prior service cost	—	7,382	—	—
Amortization of prior service (cost) benefit	(1,163)	(73)	1,537	1,537
Total Other Changes	**(48,211)**	**(39,834)**	**690**	**1,551**
Total Recognized	**$ (36,221)**	**$ (21,053)**	**$ (1,576)**	**$ 5**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2021**	**2020**	**2021**	**2020**
Discount rate	2.96%	2.56%	2.85%	2.29%
Rate of compensation increase	3.80%	3.80%	N/A	N/A
Interest crediting rate	N/A	N/A	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rates by developing yield curves derived from a portfolio of high grade non-callable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2021 and 2020 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2021**	**2020**	**2021**	**2020**
Discount rate	2.56%	3.19% / 2.58%	2.29%	3.19%
Expected long-term return on plan assets	7.00%	7.40%	5.70%	6.25%
Rate of compensation increase	3.80%	3.80%	N/A	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the PURA.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2021 and 2020 consisted of:

As of December 31,	**2021**	**2020**
Health care cost trend rate assumed for next year	6.50% / 5.25%	6.50% / 5.25%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2025	2029 / 2025

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We do not expect to contribute to our pension plan during 2022. We expect to contribute $3.2 million to our other postretirement benefit plans during 2022.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2021 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2022	$ 39,280	$ 4,012	$ —
2023	$ 34,807	$ 3,970	$ —
2024	$ 37,396	$ 3,815	$ —
2025	$ 34,131	$ 3,789	$ —
2026	$ 34,338	$ 3,683	$ —
2027 - 2031	$ 169,114	$ 17,265	$ —

Plan assets

Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 8,158	$ 1,909	$ 6,249	$ —
U.S. government securities	24,530	24,530	—	—
Common stocks	18,862	18,862	—	—
Registered investment companies	39,979	39,979	—	—
Corporate bonds	112,211	—	112,211	—
Preferred stocks	121	121	—	—
Common collective trusts	154,514	—	154,514	—
Other, principally annuity, fixed income	2,966	1	2,965	—
	$ 361,341	**$ 85,402**	**$ 275,939**	**$ —**
Other investments measured at net asset value	61,831			
Total	**$ 423,172**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 14,623	$ 14	$ 14,609	$ —
U.S. government securities	24,303	24,296	7	—
Common stocks	14,512	14,512	—	—
Registered investment companies	41,087	41,087	—	—
Corporate bonds	97,255	—	97,255	—
Preferred stocks	134	134	—	—
Common collective trusts	157,458	—	157,458	—
Other, principally annuity, fixed income	582	872	(290)	—
	$ 349,954	**$ 80,915**	**$ 269,039**	**$ —**
Other investments measured at net asset value	79,284			
Total	**$ 429,238**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stock - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.

- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Our postretirement benefits plan assets are invested in a VEBA arrangement that is not subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49%-69% for equity securities and 31%-51% for fixed income. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021			**Fair Value Measurements**	
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 1,375	$ —	$ 1,375	$ —
Registered investment companies	36,858	36,858	—	—
Total	**$ 38,233**	**$ 36,858**	**$ 1,375**	**$ —**

The fair values of pension benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 1,700	$ —	$ 1,700	$ —
U.S. government securities	251	251	—	—
Common stocks	147	147	—	—
Registered investment companies	22,791	22,791	—	—
Corporate bonds	1,004	—	1,004	—
Preferred stocks	1	1	—	—
Common collective trusts	1,602	—	1,602	—
Other, principally annuity, fixed income	5,949	9	5,940	—
	$ 33,445	**$ 23,199**	**$ 10,246**	**$ —**
Other investments measured at net asset value	812			
Total	**$ 34,257**			

Valuation techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stock - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2021 and 2020.

Note 14. Equity Method Investments

UI is a party to a 50-50 joint venture with Clearway Energy, Inc. in GenConn, which operates two peaking generation plants in Connecticut. UI’s investment in GenConn is being accounted for as an equity investment, the carrying value of which was $86.6 million and $91.0 million as of December 31, 2021 and December 31, 2020, respectively.

UI's pre-tax income from its equity investment in GenConn was $6.3 million and $8.2 million for the years ended December 31, 2021 and 2020, respectively.

Cash distributions from GenConn are reflected as either distributions of earnings or as returns of capital in the operating and investing sections of the statements of cash flows, respectively. UI received cash distributions from GenConn of $10.7 million and $10.9 million during the years ended December 31, 2021 and 2020, respectively.

The following represents summarized financial information of GenConn as of and for the years ended December 31, 2021 and 2020, respectively:

Years Ended December 31,		**2021**		**2020**
(Thousands)				
Current assets	$	37,833	$	39,733
Non-current assets	$	328,069	$	344,354
Current liabilities	$	15,426	$	17,229
Non-current liabilities	$	177,577	$	185,097
Operating revenues	$	54,701	$	59,671
Income	$	12,612	$	17,008

Note 15. Other Income and Other Deductions

Other income and other deductions for the years ended December 31, 2021 and 2020, respectively, consisted of:

Years Ended December 31,		**2021**		**2020**
(Thousands)				
Interest and dividends income	$	3,671	$	2,115
Allowance for funds used during construction		9,852		7,972
Carrying costs on regulatory assets		9,591		1,717
Miscellaneous		20		1,170
Total other income	**$**	**23,134**	**$**	**12,974**
Pension non-service components	$	(1,860)	$	(12,098)
Miscellaneous		(1,339)		(1,110)
Total other deductions	**$**	**(3,199)**	**$**	**(13,208)**

Note 16. Related Party Transactions

Certain Networks subsidiaries, including UI, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For UI, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including UI, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating services provided to UI by AGR and its affiliates was approximately $74.9 million and $59.8 million for the years ended December 31, 2021 and 2020, respectively.

The balance in accounts payable to affiliates of $70.0 million at December 31, 2021 and $28.6 million at December 31, 2020 is primarily due to UIL Holdings. The balance in accounts receivable from affiliates of $1.2 million at December 31, 2021 and $15.2 million at December 31, 2020 is receivable from various companies.

The balance in notes receivable from affiliates of $64.6 million at December 31, 2021 was due from NYSEG. The balance in notes receivable from affiliates of $15.0 million at December 31, 2020 was due from CMP. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

Note 17. Subsequent Events

The company has performed a review of subsequent events through April 14, 2022, which is the date these financial statements were available to be issued.