The United Illuminating Company

Financial Statements

As of and for the Years Ended December 31, 2023 and 2022

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, 2023 and 2022, 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, 2023 and 2022, 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 available to be 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 11, 2024

The United Illuminating Company
Statements of Income

Years Ended December 31,		2023		2022
(Thousands)				
Operating Revenues	**$**	**1,356,118**	**$**	**1,155,867**
Operating Expenses				
Electricity purchased		545,523		395,596
Operations and maintenance		432,461		386,328
Depreciation and amortization		114,380		113,006
Taxes other than income taxes, net		110,495		101,082
Total Operating Expenses		**1,202,859**		**996,012**
Operating Income		**153,259**		**159,855**
Other income		23,960		21,420
Other deductions		(1,868)		(9,730)
Earnings from equity method investments		2,975		3,579
Interest expense, net of capitalization		(41,987)		(41,881)
Income Before Income Tax		**136,339**		**133,243**
Income tax expense		23,801		20,554
Net Income	**$**	**112,538**	**$**	**112,689**

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

The United Illuminating Company
Statements of Comprehensive Income

Years Ended December 31,		2023		2022
(Thousands)				
Net Income	**$**	**112,538**	**$**	**112,689**
Other Comprehensive Income (Loss)				
Amortization of pension cost for non-qualified plans and current year actuarial gain (loss), net of income tax benefit of ($95) for 2023 and tax expense of $1,095 for 2022, respectively		(258)		2,995
Reclassification to net income of loss on settled cash flow hedges, net of income tax expense of $0 for 2023 and $7 for 2022, respectively		—		16
Other Comprehensive Income (Loss)		**(258)**		**3,011**
Comprehensive Income	**$**	**112,280**	**$**	**115,700**

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

The United Illuminating Company
Balance Sheets

As of December 31,	2023	2022
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 4,359	$ 1
Accounts receivable and unbilled revenues, net	200,295	170,213
Accounts receivable from affiliates	4,471	1,528
Notes receivable from affiliates	—	82,600
Materials and supplies	12,046	8,380
Derivative assets	454	489
Prepayments and other current assets	10,387	5,196
Income tax receivable	2,544	—
Regulatory assets	132,434	55,984
Total Current Assets	**366,990**	**324,391**
Utility plant, at original cost	3,791,867	3,642,320
Less accumulated depreciation	(1,137,053)	(1,046,592)
Net Utility Plant in Service	**2,654,814**	**2,595,728**
Construction work in progress	372,242	268,805
Total Utility Plant	**3,027,056**	**2,864,533**
Operating lease right-of-use assets	11,790	12,552
Equity method investments	78,747	82,533
Other property and investments	16,740	13,594
Regulatory and Other Assets		
Regulatory assets	305,644	318,819
Derivative assets	445	857
Other	25,605	23,871
Total Regulatory and Other Assets	**331,694**	**343,547**
Total Assets	**$ 3,833,017**	**$ 3,641,150**

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

The United Illuminating Company
Balance Sheets

As of December 31,		2023		2022
(Thousands)				
Liabilities				
Current Liabilities				
Current portion of debt	$	—	$	139,044
Notes payable to affiliates		24,400		—
Accounts payable and accrued liabilities		170,503		159,724
Accounts payable to affiliates		71,314		68,294
Interest accrued		10,841		10,349
Taxes accrued		16,636		18,714
Operating lease liabilities		703		655
Derivative liabilities		16,777		16,580
Other current liabilities		41,712		37,851
Regulatory liabilities		13,650		97,766
Total Current Liabilities		**366,536**		**548,977**
Regulatory and Other Liabilities				
Regulatory liabilities		333,670		347,239
Other Non-current Liabilities				
Deferred income taxes		446,803		406,302
Pension and other postretirement		119,176		121,433
Operating lease liabilities		15,474		16,048
Derivative liabilities		14,050		29,388
Environmental remediation costs		24,019		19,316
Other		31,417		30,968
Total Regulatory and Other Liabilities		**984,609**		**970,694**
Non-current debt		1,038,310		785,140
Total Liabilities		**2,389,455**		**2,304,811**
Commitments and Contingencies				
Common Stock Equity				
Common stock (no par value, 30,000,000 shares authorized and 100 shares outstanding at December 31, 2023 and December 31, 2022)		1		1
Additional paid-in capital		906,595		806,652
Retained earnings		544,655		537,117
Accumulated other comprehensive loss		(7,689)		(7,431)
Total Common Stock Equity		**1,443,562**		**1,336,339**
Total Liabilities and Equity	**$**	**3,833,017**	**$**	**3,641,150**

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

The United Illuminating Company
Statements of Cash Flows

Years Ended December 31,	2023	2022
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 112,538**	**$ 112,689**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	114,380	113,006
Regulatory assets/liabilities amortization	(79,700)	(36,343)
Regulatory assets/liabilities carrying cost	(4,860)	(5,316)
Amortization of debt issuance costs	552	437
Deferred taxes	27,811	(10,100)
Pension cost	5,703	9,027
Stock-based compensation	55	45
Earnings from equity method investments	(2,963)	(3,569)
Cash distribution from equity method investments	2,965	3,578
Other non-cash Items	(12,394)	(5,886)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(33,025)	(22,794)
Inventories	(3,666)	1,412
Accounts payable, to affiliates, and accrued liabilities	(18,446)	(9,286)
Taxes accrued	(4,623)	(8,261)
Other assets/liabilities	17,231	(30,216)
Regulatory assets/liabilities	(123,136)	113,787
Net Cash (Used in) Provided by Operating Activities	**(1,578)**	**222,210**
Cash Flow from Investing Activities:		
Capital expenditures	(218,212)	(198,444)
Contributions in aid of construction	4,829	3,623
Notes receivable from affiliates	82,600	(18,000)
Proceeds from sale of utility plant	397	168
Cash distribution from equity method investments	3,784	4,015
Net Cash Used in Investing Activities	**(126,602)**	**(208,638)**
Cash Flow from Financing Activities:		
Non-current debt issuance	188,138	198,929
Repayments of non-current debt	(75,000)	(162,500)
Notes payable to affiliates	24,400	—
Capital contribution	100,000	—
Dividends paid	(105,000)	(50,000)
Net Cash Provided by (Used in) Financing Activities	**132,538**	**(13,571)**
Net Increase in Cash and Cash Equivalents	**4,358**	**1**
Cash and Cash Equivalents, Beginning of Period	**1**	**—**
Cash and Cash Equivalents, End of Period	**$ 4,359**	**$ 1**

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, 2021	**100**	**$ 1**	**$ 806,659**	**$ 474,428**	**$ (10,442)**	**$ 1,270,646**
Net income	—	—	—	112,689	—	112,689
Other comprehensive income, net of tax	—	—	—	—	3,011	3,011
Comprehensive income						115,700
Stock-based compensation	—	—	(7)	—	—	(7)
Common stock dividends	—	—	—	(50,000)	—	(50,000)
Balance, December 31, 2022	**100**	**1**	**806,652**	**537,117**	**(7,431)**	**1,336,339**
Net income	—	—	—	112,538	—	112,538
Other comprehensive loss, net of tax	—	—	—	—	(258)	(258)
Comprehensive income						112,280
Stock-based compensation	—	—	(57)	—	—	(57)
Capital contribution	—	—	100,000	—	—	100,000
Common stock dividends	—	—	—	(105,000)	—	(105,000)
Balance, December 31, 2023	**100**	**$ 1**	**$ 906,595**	**$ 544,655**	**$ (7,689)**	**$ 1,443,562**

(*) 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 342,200 customers as of December 31, 2023 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 81.6% 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 primarily 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 and other equity investments 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 equity method investments 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 rates for depreciation were 2.8% of average depreciable property for 2023 and 2.9% for 2022. We amortize our capitalized software cost, which is included in other plant, using the straight line method, based on useful lives of 1-15 years. Capitalized software costs were approximately $312.5 million as of December 31, 2023, and $298.8 million as of December 31, 2022. Depreciation expense was $98.1 million in 2023 and $95.6 million in 2022. Amortization of capitalized software was $16.2 million in 2023 and $17.4 million in 2022.

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)**		**2023**		**2022**
(Thousands)					
Distribution	5-75	$	2,165,258	$	2,067,777
Transmission	5-60		1,149,793		1,109,846
Other	1-58		476,816		464,697
Total Utility Plant in Service			**3,791,867**		**3,642,320**
Total accumulated depreciation			(1,137,053)		(1,046,592)
Total Net Utility Plant in Service			**2,654,814**		**2,595,728**
Construction work in progress			372,242		268,805
Total Utility Plant		**$**	**3,027,056**	**$**	**2,864,533**

***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.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2023		2022
(Thousands)				
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	32,600	$	36,633
Income taxes paid, net	$	7,362	$	36,715

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $6.0 million in 2023 and $3.6 million in 2022. Accrued liabilities for utility plant additions were $62.2 million as of December 31, 2023 and $27.5 million as of December 31, 2022.

***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 $57.0 million for 2023 and $50.8 million for 2022, and are shown net of an allowance for credit losses at December 31 of $15.0 million for 2023 and $13.5 million for 2022. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $51.3 million in 2023 and $34.3 million in 2022.

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. We 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 2044.

***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 (PBO). 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. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the UI Pension Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. We amortize unrecognized actuarial gains and losses in excess of 5% of the greater of PBO or market-related value of assets (MRVA) related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the UI Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. 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*:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The CAMT and other various applicable provisions of the IRS are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year, as well as on anticipated guidance from the U.S. Department of Treasury.

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 receivable balance due from AGR was $2.5 million at December 31, 2023. The aggregate amount of related party income tax payable balance due to AGR was $7.4 million at December 31, 2022.

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 regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit 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. We consider the effect of the alternative minimum tax system in determining the need for a valuation allowance for deferred taxes. 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.

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.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2023 that are expected to have a material impact on UI's financial statements.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on UI's financial statements.

(a) Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance to enhance income tax disclosures. The two primary enhancements relate to disaggregation of the annual disclosures for the effective tax rate reconciliation and income taxes paid. For the rate reconciliation, it requires additional disaggregation of information in a tabular format using both percentages and amounts broken out into specific categories (e.g., state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, and changes in unrecognized tax benefits). For income taxes paid, it requires disaggregation by jurisdiction (e.g., federal, state and foreign). We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

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.

Union collective bargaining agreements**:** Approximately 62.8% 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 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 previously approved three-year distribution rate schedules became effective January 1, 2017 through December 31, 2019, and included, 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. Given the expiration of the rate plan, UI has been operating under the 2019 approved rate schedules.

On September 9, 2022, UI filed a distribution revenue requirement case. UI's filing proposes a three-year rate plan commencing September 1, 2023 through August 31, 2026. The filing is based on a test year ending December 31, 2021, for the rate years beginning September 1, 2023 ("UI Rate Year 1"), September 1, 2024 ("UI Rate Year 2"), and September 1, 2025 ("UI Rate Year 3"). UI is requesting that PURA approve new distribution rates to recover an increase in revenue requirements of approximately $91 million in UI Rate Year 1, an incremental approximately $20 million in UI Rate Year 2, and an incremental approximately $19 million in UI Rate Year 3, compared to total revenues that would otherwise be recovered under UI's current rate schedules. UI's Rate Plan also includes several measures to moderate the impact of the proposed rate update for all customers, including, without limitation a rate levelization proposal to spread the proposed total rate increase over the three rate years, which would result in a change in revenue in UI Rate Year 1 of approximately $54 million. Other parties filed direct testimony on December 13, 2022 and UI filed its rebuttal testimony on January 6, 2023. In February and March, 2023, UI attended 15 days of evidentiary hearings in support of its application. PURA issued a Final Decision on August 25, 2023, which approved an annual revenue requirement of $384.9 million and a 1-year rate plan commencing on September 1, 2023. This represents an increase of $22.9 million to the Company's currently approved base distribution revenue requirement. PURA established an allowed return on equity of 9.10%, but reduced the allowed ROE by an aggregate 47 basis point reduction (i.e., to 8.63%), subject to certain conditions and timelines. The Final Decision established a capital structure consisting of 50% common equity and 50% debt. The Final Decision results in an average increase in base distribution rates of about 6.6% and an average increase in customer bills of about 2% compared to current levels. On September 18, 2023, UI filed an appeal of the PURA's Final Decision in Connecticut Superior Court, because of actual and legal errors related to the treatment of deferred assets, plant in service, and operating expenses. We cannot predict the outcome of this matter.

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 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.

On June 29, 2023, the Governor of Connecticut signed into law an energy bill titled *An Act Strengthening Protections for Connecticut Consumers*, which, among other things, provided PURA with additional powers to regulate the State's public service companies. More specifically, the Act modified certain ratemaking mechanisms such as revenue decoupling, allows PURA to initiate more frequent rate reviews in between rate cases, modifies electric distribution billing formats, precludes recovery of rate case expenses and appeals from rate proceedings, and mandates various reporting requirements.

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.

At the conclusion of the period ended December 31, 2023, UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2024 and 50% of the second half of 2024. Supplier of last resort service is procured on a quarterly basis and UI has a wholesale power supply agreement in place for the first quarter of 2024.

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, 2023, UI would have had to post collateral of approximately $46.4 million. We would have been and remain able to provide such 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 Renewable Energy Certificates (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 October of 2018, UI entered into five Power Purchase Agreements (PPAs) totaling approximately 50 MW from developers of offshore wind and fuel cell generation pursuant to state law that provides the net costs of the PPAs are recoverable through electric rates. On December 19, 2018, PURA approved the PPAs, and approved UI’s use of the non-bypassable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

In 2019, UI entered into PPAs with 11 projects, totaling approximately 12 million MWh, pursuant to state law that provides that the net costs of the PPAs are recoverable through electric rates. UI terminated eight of these contracts in 2022 and 2023, and the remaining three projects with existing contracts from these 2019 procurements are with Millstone Nuclear, Seabrook Nuclear and Revolution Wind.

In 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. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates. On October 13, 2023, PURA approved the termination of this agreement between UI and its affiliate for the development of Park City Wind Project.

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 made 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 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 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 $8.5 million as of December 31, 2023, which has not changed since December 31, 2022, 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 $4.2 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 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. On August 9, 2022, the D.C. Circuit Court vacated FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the RPM after initially, and forcefully, rejecting it and that because FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. We cannot predict the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the NETO's 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 three 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 $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 30, 2023, seeking approval of its 2024 revenue requirements for the period commencing January 1, 2024 for both the GenConn Devon and GenConn Middletown facilities. As required by PURA Order 1 in the 2023 Decision GenConn's calculation for revenue requirements totaled $44 million. While the company was required to file its application consistent with PURA's order in the 2023 decision, GenConn has reserved the right to update revenue requirements following outcomes of legal appeals of the last 3 decisions. Following a Draft Decision provided on October 16, 2023, a Final Decision was issued on November 8, 2023. On December 21, 2023 the company filed an appeal of the 2024 PURA decision at CT Superior Court. The company cannot predict the outcome of the appeal.

GenConn filed its annual revenue requirements request with PURA on June 30, 2022, seeking approval of its 2023 revenue requirements for the period commencing January 1, 2023 for both the GenConn Devon and GenConn Middletown facilities. As required by PURA Order 1 in the 2022 Decision GenConn's calculation for revenue requirements totaled $44.7 million. On October 24, 2022 PURA issued a final decision approving revenue requirement of $44.0 million ($19.2 million for GenConn Devon, and $24.8 million for GenConn Middletown). Additionally, GenConn was granted a 9.85% Return on Equity (ROE) for 2023. PURA disallowed $0.7 million associated with recommended capital and expenses projects and costs associated with Working Capital Facility renewal necessary in 2023. GenConn has filed a 2023 Decision appeal before the CT Superior Court on January 27, 2023. The 2022 Decision appeal before CT Superior Court remains open but stayed pending the outcome of the 2021 Decision Appeal. The company cannot predict the outcome of the appeal.

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 8, 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. On October 17, 2022 the company filed a brief to Superior Court of the 2022 appeal. A stay of the case was granted on January 6, 2023 pending the decision of the CT Supreme Court case on the 2021 revenue requirements decision. The company cannot predict the outcome of the appeal.

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 was dismissed on January 28, 2022. On February 16, 2022, GenConn initiated an appeal at the Connecticut Appellate Court, which requested transfer to the Connecticut Supreme Court. The high court agreed to hear the case. Oral arguments occurred on September 8, 2023 and the case 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 $44.7 million of the regulatory liability related to accumulated Tax Act savings back to customers over an accelerated 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, 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 Tropical 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. On October 17, 2022, the court denied UI's appeal and affirmed PURA's decisions in their entirety. UI filed a notice of appeal to Connecticut's Appellate court on November 7, 2022. This matter has been briefed and oral argument was held December 11, 2023. We cannot predict the outcome of this proceeding.

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 $257.4 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.

Regulatory assets at December 31, 2023 and 2022 consisted of:

As of December 31,	2023	2022
(Thousands)		
Contracts for differences	$ 29,928	$ 44,602
COVID-19 cost recovery	8,550	8,759
Deferred transmission expense	1,097	—
Environmental remediation costs	6,916	6,557
Excess generation service charge	52,401	23,889
Non-bypassable charges	14,421	—
Pension and other postretirement benefit plans	87,589	88,795
Pension and other postretirement benefits cost deferrals	21,026	19,880
Revenue decoupling mechanism	10,399	13,288
Storm costs	25,384	26,875
System benefit charge	29,165	2,160
Unamortized losses on reacquired debt	4,456	4,956
Unfunded future income taxes	124,727	118,417
Other	22,019	16,625
Total regulatory assets	**438,078**	**374,803**
Less: current portion	132,434	55,984
Total non-current regulatory assets	**$ 305,644**	**$ 318,819**

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 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 benefit plans 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. 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.

System benefits charge represents the mechanism by which UI recovers costs associated with hardship uncollectible customer accounts, arrearage forgiveness programs, and other customer assistance programs. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

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 and electric vehicle programs.

Regulatory liabilities at December 31, 2023 and 2022 consisted of:

As of December 31,	2023	2022
(Thousands)		
2017 Tax Act	$ 206,288	$ 219,439
Accrued removal obligations	80,709	76,263
Accumulated deferred investment tax credits	9,898	10,628
Conservation and load management	6,176	3,790
Deferred transmission expense	—	11,465
Middletown/Norwalk local transmission network service collections	15,669	16,242
Non-bypassable charges	—	70,308
Pension and other postretirement benefit plans	12,619	22,909
Pension and other postretirement benefits cost deferrals	1,974	1,063
Rate refund - FERC ROE proceeding	8,507	7,892
Other	5,480	5,006
Total regulatory liabilities	**347,320**	**445,005**
Less: current portion	13,650	97,766
Total non-current regulatory liabilities	**$ 333,670**	**$ 347,239**

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.

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.

Deferred transmission expense represents deferred transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

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.

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 benefit plans represent the actuarial gains 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. The recovery of these amounts will be determined in future proceedings.

Rate refund - FERC ROE proceeding represents the reserve associated with the FERC proceeding around the base return on equity (ROE) reflected in ISO-NE's open access transmission tariff.

Other includes items such as deferral of CAM gross earnings tax expense collected in base distribution rates for periods between January 1, 2020 and August 31, 2023.

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, 2023 and 2022 are as follows:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Regulated operations – electricity	$	1,307,393	$	1,124,779
Other (a)		8,811		6,871
Revenue from contracts with customers		**1,316,204**		**1,131,650**
Leasing revenue		6,399		4,114
Alternative revenue programs		26,356		18,346
Other revenue		7,159		1,757
Total operating revenues	**$**	**1,356,118**	**$**	**1,155,867**

(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 (benefit) for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Current				
Federal	$	(2,926)	$	24,194
State		(354)		6,460
Current taxes charged to (benefit) expense		**(3,280)**		**30,654**
Deferred				
Federal		24,726		(13,562)
State		3,085		4,192
Deferred taxes charged to expense (benefit)		**27,811**		**(9,370)**
Investment tax credits		(730)		(730)
Total Income Tax Expense	**$**	**23,801**	**$**	**20,554**

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, 2023 and 2022 consisted of:

Years Ended December 31,	2023	2022
(Thousands)		
Tax expense at federal statutory rate	$ 28,631	$ 27,981
Depreciation/amortization and other plant differences not normalized	(1,538)	(3,255)
State taxes net of federal benefit	2,158	8,415
Investment tax credit amortization	(730)	(730)
Excess ADIT amortization	(4,731)	(12,524)
Other, net	11	667
Total Income Tax Expense	**$ 23,801**	**$ 20,554**

Income tax expense for the year ended December 31, 2023 was $4.8 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess Accumulated Deferred Income Tax (ADIT)amortization, and depreciation/amortization and other plant differences not normalized, partially offset by state taxes. This resulted in an effective tax rate of 17.5%. Income tax expense for the year ended December 31, 2022 was $7.4 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 15.4%

Deferred tax assets and liabilities as of December 31, 2023 and 2022 consisted of:

December 31,	2023	2022
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 442,597	$ 426,093
Unfunded future income taxes	33,510	31,899
Federal and state tax credits	(4,051)	(190)
Investment in GenConn	31,564	31,758
Postretirement benefits	(10,693)	(8,737)
Regulatory liability due to "Tax Cuts and Jobs Act"	(55,543)	(59,084)
Other	9,419	(15,437)
Total Non-current Deferred Income Tax Liabilities	**$ 446,803**	**$ 406,302**
Deferred tax assets	$ 70,287	$ 83,448
Deferred tax liabilities	517,090	489,750
Net Accumulated Deferred Income Tax Liabilities	**$ 446,803**	**$ 406,302**

As of December 31, 2023, UI had $4.1 million of state tax credit carry forwards with no valuation allowance offset. The state tax credit carry forwards will begin to expire in 2028. As of December 31, 2022, UI had $0.2 million of gross state tax credit carry forwards with no valuation allowance offset.

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, 2023 and 2022, 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, 2023 and 2022.

Note 6. Non-current Debt

Long-term debt as of December 31, 2023 and 2022 consisted of:

As of December 31,		2023		2022	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured notes	2025 - 2049	$ 1,044,460	2.02% - 6.51%	$ 929,460	2.02% - 6.51%
Unamortized debt issuance costs and discount		(6,150)		(5,276)	
Total Debt		**1,038,310**		**924,184**	
Less: debt due within one year, included in current liabilities		—		139,044	
Total Non-current Debt		**$ 1,038,310**		**$ 785,140**	

On December 13, 2023, UI issued $156 million aggregate principal amount of unsecured notes maturing in 2034 at an interest rate of 6.09% and $34 million aggregate principal amount of unsecured notes maturing in 2038 at an interest rate of 6.29%.

On October 2, 2023, UI issued $64 million aggregate principal amount of unsecured notes maturing in 2033 at an interest rate of 4.50%. The issuance was related to notes maturing on October 2, 2023, which were remarketed, resulting in a non-cash activity.

On January 1, 2022, UI issued $150 million aggregate principal amount of unsecured notes maturing in 2032 at an interest rate of 2.25%.

On December 15, 2022, UI issued $50 million aggregate principal amount of unsecured notes maturing in 2032 at an interest rate of 4.62%.

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

2024	2025	2026	2027	2028	Total
(Thousands)					
$ —	$ 100,000	$ —	$ —	$ 100,000	$ 200,000

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2023 and 2022.

Note 7. Bank Loans and Other Borrowings

UI had $24.4 million in short-term debt outstanding at December 31, 2023 and no short-term debt outstanding at December 31, 2022. 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, 2023 and December 31, 2022.

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 $24.4 million in debt outstanding under this agreement at December 31, 2023 and no debt outstanding under this agreement at December 31, 2022.

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, 2023 and December 31, 2022.

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 0.43 to 1.00 at December 31, 2023. We are not in default as of December 31, 2023.

Note 8. Preferred Stock

At December 31, 2023, 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 40 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,		2023		2022
(Thousands)				
Lease cost				
Operating lease cost	$	3,415	$	4,377
Short-term lease cost		172		65
Variable lease cost		127		411
Total lease cost	**$**	**3,714**	**$**	**4,853**

Balance sheet and other information for the years ended December 31, 2023 and 2022 was as follows:

As of December 31,		2023		2022
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right-of-use assets	$	11,790	$	12,552
Operating lease liabilities, current		703		655
Operating lease liabilities, long-term		15,474		16,048
Total operating lease liabilities	$	16,177	$	16,703
Weighted-average Remaining Lease Term (years)				
Operating leases		20.49		21.22
Weighted-average Discount Rate				
Operating leases		3.72%		3.72%

For the years ended December 31, 2023 and 2022, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,		2023		2022
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	1,184	$	1,481
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	115	$	2,038

As of December 31, 2023, maturities of lease liabilities were as follows:

(Thousands)		Operating Leases
Year ending December 31,		
2024	$	1,127
2025		988
2026		997
2027		3,318
2028		853
Thereafter		17,542
Total lease payments		**24,825**
Less: imputed interest		(8,648)
Total	**$**	**16,177**

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.

The amount reserved related to English Station was $19.4 million as of both December 31, 2023 and 2022. 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, 2023 and December 31, 2022, the amount reserved for this property was $8.0 million and $7.9 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 as of both December 31, 2023 and 2022.

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, 2023, UI has recorded a gross derivative asset of $0.9 million ($0 of which is related to UI’s portion of the CfD signed by CL&P), a regulatory asset of $29.9 million, a gross derivative liability of $30.8 million ($29.7 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, 2022, UI had recorded a gross derivative asset of $1.3 million ($0 of which is related to UI’s portion of the CfD signed by CL&P), a regulatory asset of $44.6 million, a gross derivative liability of $45.9 million ($44.3 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, 2023 and 2022, respectively, were as follows:

	Years Ended December 31, 2023	Years Ended December 31, 2022
(Thousands)		
Derivative assets	$ (447)	$ (365)
Derivative liabilities	$ 15,121	$ 14,435

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, 2023 and 2022, 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)				
2023				
Foreign exchange contracts	$ —	Operations and maintenance	$ —	$ 432,461
Total	**$ —**		**$ —**	
2022				
Foreign exchange contracts	$ —	Operations and maintenance	$ (23)	$ 386,328
Total	**$ —**		**$ (23)**	

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,016 million as of December 31, 2023 and $860 million as of December 31, 2022. 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, 2023 and December 31, 2022, consisted of:

As of December 31, 2023		Level 1		Level 2		Level 3		Total
(Thousands)								
Derivative assets								
Contracts for differences	$	—	$	—	$	899	$	899
Equity investments with readily determinable fair values								
Supplemental retirement benefit trust life insurance policies		—		16,493		—		16,493
Total	**$**	**—**	**$**	**16,493**	**$**	**899**	**$**	**17,392**
Derivative liabilities								
Contracts for differences	$	—	$	—	$	(30,827)	$	(30,827)
Total	**$**	**—**	**$**	**—**	**$**	**(30,827)**	**$**	**(30,827)**

As of December 31, 2022		Level 1		Level 2		Level 3		Total
(Thousands)								
Derivative assets								
Contracts for differences	$	—	$	—	$	1,346	$	1,346
Equity investments with readily determinable fair values								
Supplemental retirement benefit trust life insurance policies		—		13,360		—		13,360
Total	**$**	**—**	**$**	**13,360**	**$**	**1,346**	**$**	**14,706**
Derivative liabilities								
Contracts for differences	$	—	$	—	$	(45,948)	$	(45,948)
Foreign exchange contracts		—		(20)		—		(20)
Total	**$**	**—**	**$**	**(20)**	**$**	**(45,948)**	**$**	**(45,968)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2023 and 2022. 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, 2023**	**Range at December 31, 2022**
Risk of non-performance	0.42% - 0.52%	0.84% - 0.89%
Discount rate	3.84% - 4.01%	3.99% - 4.22%
Forward pricing ($ per MW)	$2.00 - $2.61	$2.00 - $3.80

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2023 and 2022, respectively, is as follows:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Beginning balance	$	(44,602)	$	(58,672)
Unrealized gains, net		14,674		14,070
Ending balance	**$**	**(29,928)**	**$**	**(44,602)**

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 $8.1 million for 2023 and $9.2 million for 2022.

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 $10.6 million and $10.2 million at December 31, 2023 and 2022, 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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 390,971**	**$ 561,934**	**$ 40,885**	**$ 61,916**
Service cost	—	2,195	267	542
Interest cost	19,462	18,491	2,019	1,708
Plan amendments	—	448	—	—
Actuarial loss (gain)	21,898	(118,557)	9,935	(18,041)
Curtailments	—	(17,540)	—	—
Settlements	—	(27,706)	—	—
Benefits paid	(31,593)	(28,294)	(5,256)	(5,240)
Benefit obligation as of December 31,	**$ 400,738**	**$ 390,971**	**$ 47,850**	**$ 40,885**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 279,538**	**$ 423,172**	**$ 30,885**	**$ 38,233**
Actual return on plan assets	36,864	(87,634)	5,202	(5,891)
Employer contributions	10,230	—	3,542	3,783
Settlements	—	(27,706)	—	—
Benefits paid	(31,593)	(28,294)	(5,256)	(5,240)
Fair value of plan assets at December 31,	**$ 295,039**	**$ 279,538**	**$ 34,373**	**$ 30,885**
Funded status at December 31,	**$ (105,699)**	**$ (111,433)**	**$ (13,477)**	**$ (10,000)**

During 2023, the pension benefit obligation had an actuarial loss of $21.9 million, primarily due to a $20.0 million loss from decreases in discount rates. During 2023, the postretirement benefit obligation had an actuarial loss of $9.9 million, primarily due to a $6.0 million loss from assumption changes in health care trend rates and $2.2 million loss from decreases in discount rates.

During 2022, the pension benefit obligation had an actuarial gain of $118.6 million, primarily due to a $107.5 million gain from increases in discount rates. In 2022, the pension benefit obligation had a reduction of $27.7 million from settlements and $17.5 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. During 2022, the postretirement benefit obligation had an actuarial gain of $18.0 million, primarily due to a $10.7 million gain from increases in discount rates.

Amounts recognized as of December 31, 2023 and 2022 consisted of:

		Pension Benefits			Postretirement Benefits			
As of December 31,		**2023**		**2022**		**2023**		**2022**
(Thousands)								
Non-current liabilities	$	(105,699)	$	(111,433)	$	(13,477)	$	(10,000)

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, 2023 and 2022 consisted of:

		Pension Benefits			Postretirement Benefits			
Years Ended December 31,		**2023**		**2022**		**2023**		**2022**
(Thousands)								
Net loss (gain)	$	83,353	$	83,371	$	(7,029)	$	(16,268)
Prior service cost (credit)	$	4,236	$	5,424	$	—	$	(1,056)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $400.7 million and $391.0 million as of December 31, 2023 and 2022, respectively. Our postretirement benefits were partially funded at December 31, 2023 and 2022.

The PBO and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2023 and 2022. 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,		**2023**		**2022**
(Thousands)				
Projected benefit obligation	$	400,738	$	390,971
Accumulated benefit obligation	$	400,738	$	390,971
Fair value of plan assets	$	295,039	$	279,538

As of December 31, 2023 and 2022, 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, 2023 and 2022 consisted of:

For the years ended December 31,	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ —	$ 2,195	$ 267	$ 542
Interest cost	19,462	18,491	2,019	1,708
Expected return on plan assets	(18,645)	(24,564)	(2,162)	(2,256)
Amortization of prior service cost (credit)	1,188	1,171	(1,056)	(1,537)
Amortization of actuarial loss (gain)	3,698	5,826	(2,344)	(982)
Settlements	—	5,908	—	—
Net Periodic Benefit Cost	**$ 5,703**	**$ 9,027**	**$ (3,276)**	**$ (2,525)**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Curtailments	$ —	$ (17,540)	$ —	$ —
Settlements	—	(5,908)	—	—
Current year prior service cost	—	448	—	—
Amortization of prior service (cost) benefit	(1,188)	(1,171)	1,056	1,537
Current year actuarial loss (gain)	3,679	(6,359)	6,895	(9,894)
Amortization of actuarial (loss) gain	(3,698)	(5,826)	2,344	982
Total Other Changes	**$ (1,207)**	**$ (36,356)**	**$ 10,295**	**$ (7,375)**
Total Recognized	**$ 4,496**	**$ (27,329)**	**$ 7,019**	**$ (9,900)**

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, 2023 and 2022 consisted of:

As of December 31,	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
Discount rate	4.69%	5.21%	4.65%	5.17%
Rate of compensation increase	N/A	N/A	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, 2023 and 2022 consisted of:

Years Ended December 31,	Pension Benefits 2023	2022	Postretirement Benefits 2023	2022
Discount rate	5.21%	2.96% / 4.15% / 5.00%	5.17%	2.85%
Expected long-term return on plan assets	7.50%	7.00%	7.00%	5.90%
Rate of compensation increase	N/A	3.80% Non-Union; 3.00% Union / N/A Non-Union; 3.00% Union / N/A	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 in excess of 5% of the greater of PBO or MRVA related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the UI Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2023 and 2022 consisted of:

As of December 31,	2023	2022
Health care cost trend rate assumed for next year	8.10% / 6.20%	6.00%/5.00%
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	2031/2028	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 expect to contribute $13.1 million to our pension plan during 2024. We expect to contribute $2.6 million to our other postretirement benefit plans during 2024.

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, 2023 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2024	$ 36,972	$ 4,179	$ —
2025	$ 33,695	$ 4,114	$ —
2026	$ 32,776	$ 4,017	$ —
2027	$ 32,657	$ 3,729	$ —
2028	$ 31,306	$ 3,659	$ —
2029 -2033	$ 144,498	$ 16,562	$ —

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 15%-70% for Return-Seeking assets and 30%-85% 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, 2023, consisted of:

As of December 31, 2023		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 7,016	$ 235	$ 6,781	$ —
U.S. government securities	31,147	31,147	—	—
Common stocks	14,498	14,498	—	—
Registered investment companies	15,044	15,044	—	—
Corporate bonds	76,790	—	76,790	—
Common collective trusts	115,026	—	115,026	—
Other, principally annuity, fixed income	(9,593)	(6)	(9,587)	—
	$ 249,928	**$ 60,918**	**$ 189,010**	**$ —**
Other investments measured at net asset value	45,111			
Total	**$ 295,039**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022	Fair Value Measurements			
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 8,676	$ 33	$ 8,643	$ —
U.S. government securities	15,320	15,320	—	—
Common stocks	12,579	12,579	—	—
Registered investment companies	14,103	14,103	—	—
Corporate bonds	73,112	—	73,112	—
Preferred stocks	76	76	—	—
Common collective trusts	105,861	—	105,861	—
Other, principally annuity, fixed income	1,057	—	1,057	—
	$ 230,784	**$ 42,111**	**$ 188,673**	**$ —**
Other investments measured at net asset value	48,754			
Total	**$ 279,538**			

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, 2023, consisted of:

As of December 31, 2023		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 168	$ —	$ 168	$ —
Registered investment companies	34,205	34,205	—	—
Total	**$ 34,373**	**$ 34,205**	**$ 168**	**$ —**

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 587	$ —	$ 587	$ —
Registered investment companies	30,298	30,298	—	—
Total	**$ 30,885**	**$ 30,298**	**$ 587**	**$ —**

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.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2023 and 2022.

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 $78.7 million and $82.5 million as of December 31, 2023 and December 31, 2022, respectively.

UI's pre-tax income from its equity investment in GenConn was $3.0 million and $3.6 million for the years ended December 31, 2023 and 2022, 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 $6.7 million and $7.6 million during the years ended December 31, 2023 and 2022, respectively.

The following represents summarized financial information of GenConn as of and for the years ended December 31, 2023 and 2022, respectively:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Current assets	$	39,282	$	39,334
Non-current assets	$	294,235	$	311,195
Current liabilities	$	14,548	$	15,952
Non-current liabilities	$	161,672	$	169,707
Operating revenues	$	50,923	$	50,212
Income	$	5,926	$	7,156

Note 15. Other Income and Other Deductions

Other income and other deductions for the years ended December 31, 2023 and 2022, respectively, consisted of:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Interest and dividends income	$	6,299	$	5,738
Allowance for funds used during construction		12,911		11,433
Carrying costs on regulatory assets		4,677		4,213
Miscellaneous		73		36
Total other income	**$**	**23,960**	**$**	**21,420**
Pension non-service components	$	586	$	(6,968)
Miscellaneous		(2,454)		(2,762)
Total other deductions	**$**	**(1,868)**	**$**	**(9,730)**

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 and capital services provided to UI by AGR and its affiliates was approximately $81.4 million and $73.8 million for the years ended December 31, 2023 and 2022, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $8.9 million in 2023 and $6.0 million in 2022, respectively. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by UI to AGR and its subsidiaries were approximately $10.9 million in 2023 and $8.7 million in 2022. 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 $71.3 million at December 31, 2023 and $68.3 million at December 31, 2022 is primarily due to UIL Holdings. The balance in accounts receivable from affiliates of $4.5 million at December 31, 2023 is primarily receivable from Avangrid Management Company, and the balance of accounts receivable from affiliates of $1.5 million at December 31, 2022 is receivable from CMP.

The balance in notes payable to affiliates of $24.4 million at December 31, 2023 was due to Avangrid, Inc. and was related to the Bi-Lateral Intercompany Facility as discussed in Note 7 of these financial statements. The balance in notes receivable from affiliates of $82.6 million at December 31, 2022 was due as follows: $16.1 million due from NYSEG, $7.0 million due from CMP, $9.6 million due from BGC, $25.5 million due from CNG, $24.4 million due from SCG and was related to the Virtual Money Pool Agreement as discussed in Note 7.

Note 17. Subsequent Events

The company has performed a review of subsequent events through April 11, 2024, which is the date these financial statements were available to be issued.

Connecticut Natural Gas Corporation
Financial Statements
As of and for the Years Ended December 31, 2023 and 2022

Connecticut Natural Gas Corporation

Index

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

Independent Auditors' Report

The Stockholders and 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, 2023 and 2022, 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, 2023 and 2022, 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 available to be 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 29, 2024

Connecticut Natural Gas Corporation
Statements of Income

Years Ended December 31,		2023		2022
(Thousands)				
Operating Revenues	$	**428,699**	$	**523,673**
Operating Expenses				
Natural gas purchased		194,191		283,662
Operations and maintenance		108,846		100,300
Depreciation and amortization		49,784		47,226
Taxes other than income taxes, net		32,492		34,594
Total Operating Expenses		**385,313**		**465,782**
Operating Income		**43,386**		**57,891**
Other income		2,822		2,344
Other (deductions) income, net		964		(5,823)
Interest expense, net of capitalization		(9,732)		(9,093)
Income Before Income Tax		**37,440**		**45,319**
Income tax expense		8,249		11,206
Net Income	$	**29,191**	$	**34,113**

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

Connecticut Natural Gas Corporation
Statements of Comprehensive Income

Years Ended December 31,		2023		2022
(Thousands)				
Net Income	$	**29,191**	$	**34,113**
Other Comprehensive Income (Loss), Net of Tax				
Amortization of pension cost for nonqualified plans and current year actuarial (loss) gain, net of income tax (benefit) expense of ($22) for 2023 and $78 for 2022		(59)		212
Total Other Comprehensive Income (Loss), Net of Tax		**(59)**		**212**
Comprehensive Income	$	**29,132**	$	**34,325**

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

Connecticut Natural Gas Corporation
Balance Sheets

As of December 31,		2023		2022
(Thousands)				
Assets				
Current Assets				
Cash and cash equivalents	$	421	$	1,070
Accounts receivable and unbilled revenues, net		107,260		149,398
Accounts receivable from affiliates		154		535
Notes receivable from affiliates		26,600		—
Gas in storage		41,998		54,803
Materials and supplies		5,603		4,809
Other current assets		4,130		1,899
Regulatory assets		50,255		57,875
Total Current Assets		**236,421**		**270,389**
Utility plant, at original cost		1,271,264		1,214,513
Less accumulated depreciation		(424,187)		(399,929)
Net Utility Plant in Service		**847,077**		**814,584**
Construction work in progress		21,284		15,370
Total Utility Plant		**868,361**		**829,954**
Operating lease right-of-use assets		2,746		2,432
Other property and investments		727		764
Regulatory and Other Assets				
Regulatory assets		75,711		62,376
Goodwill		79,341		79,341
Other		188		136
Total Regulatory and Other Assets		**155,240**		**141,853**
Total Assets	**$**	**1,263,495**	**$**	**1,245,392**

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

Connecticut Natural Gas Corporation
Balance Sheets

As of December 31,	2023	2022
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ —	$ 25,450
Accounts payable and accrued liabilities	63,158	98,916
Accounts payable to affiliates	19,077	19,880
Interest accrued	2,674	2,614
Taxes accrued	8,702	13,165
Operating lease liabilities	429	177
Regulatory liabilities	5,386	5,230
Other	18,538	16,687
Total Current Liabilities	**117,964**	**182,119**
Regulatory and Other Liabilities		
Regulatory liabilities	309,536	297,201
Other Non-current Liabilities		
Deferred income taxes	56,111	44,724
Pension and other postretirement	62,813	53,429
Operating lease liabilities	2,364	2,323
Asset retirement obligation	6,140	6,279
Other	1,448	1,121
Total Regulatory and Other Liabilities	**438,412**	**405,077**
Non-current debt	243,923	189,072
Total Liabilities	**800,299**	**776,268**
Commitments and Contingencies		
Preferred Stock	**340**	**340**
Common Stock Equity		
Common stock ($3.125 par value, 20,000,000 shares authorized and 10,634,436 shares outstanding at December 31, 2023 and 2022)	33,233	33,233
Additional paid-in capital	396,758	396,791
Retained earnings	33,172	39,008
Accumulated other comprehensive loss	(307)	(248)
Total Common Stock Equity	**462,856**	**468,784**
Total Liabilities and Equity	**$ 1,263,495**	**$ 1,245,392**

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

Connecticut Natural Gas Corporation
Statements of Cash Flows

Years Ended December 31,	2023	2022
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 29,191**	**$ 34,113**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	49,784	47,226
Regulatory assets/liabilities amortization	12,087	22,377
Regulatory assets/liabilities carrying cost	87	(615)
Amortization of debt issuance costs	134	67
Deferred taxes	6,988	3,427
Pension cost	196	(1,101)
Stock-based compensation	24	122
Accretion expenses	322	328
Gain on disposal of assets	(57)	—
Other non-cash items	276	719
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	42,519	(42,208)
Inventories	12,011	(24,841)
Accounts payable, to affiliates, and accrued liabilities	(43,928)	29,589
Taxes accrued	(4,463)	(6,233)
Other assets/liabilities	14,035	(12,836)
Regulatory assets/liabilities	(27,684)	(5,492)
Net Cash Provided by Operating Activities	**91,522**	**44,642**
Cash Flow from Investing Activities:		
Capital expenditures	(62,638)	(66,754)
Contributions in aid of construction	2,643	1,332
Proceeds from sale of utility plant	214	127
Notes receivable from affiliates	(26,600)	—
Net Cash Used in Investing Activities	**(86,381)**	**(65,295)**
Cash Flow from Financing Activities:		
Non-current debt issuance	54,687	—
Notes payable to affiliates	(25,450)	16,750
Capital contribution	—	30,000
Dividends paid	(35,027)	(25,027)
Net Cash (Used in) Provided by Financing Activities	**(5,790)**	**21,723**
Net (Decrease) Increase in Cash and Cash Equivalents	**(649)**	**1,070**
Cash and Cash Equivalents, Beginning of Period	**1,070**	**—**
Cash and Cash Equivalents, End of Period	**$ 421**	**$ 1,070**

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

Connecticut Natural 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
Balances, December 31, 2021	**10,634,436**	**$ 33,233**	**$ 366,698**	**$ 29,922**	**$ (460)**	**$ 429,393**
Net income	—	—	—	34,113	—	34,113
Other comprehensive income, net of tax	—	—	—	—	212	212
Comprehensive income						34,325
Stock-based compensation	—	—	93	—	—	93
Common stock dividends	—	—	—	(25,000)	—	(25,000)
Preferred stock dividends	—	—	—	(27)	—	(27)
Capital contribution	—	—	30,000	—	—	30,000
Balances, December 31, 2022	**10,634,436**	**33,233**	**396,791**	**39,008**	**(248)**	**468,784**
Net income	—	—	—	29,191	—	29,191
Other comprehensive loss, net of tax	—	—	—	—	(59)	(59)
Comprehensive income						29,132
Stock-based compensation	—	—	(33)	—	—	(33)
Common stock dividends	—	—	—	(35,000)	—	(35,000)
Preferred stock dividends	—	—	—	(27)	—	(27)
Balances, December 31, 2023	**10,634,436**	**$ 33,233**	**$ 396,758**	**$ 33,172**	**$ (307)**	**$ 462,856**

(*) 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 186,700 customers as of December 31, 2023, 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 81.6% 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). The accounting records of CNG are also maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC).

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 primarily 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 3.8% of average depreciable property for 2023 and 2022. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 10 years. Depreciation expense was $47.1 million in 2023 and $44.3 million in 2022. Amortization of capitalized software was $2.7 million in 2023 and $2.9 million in 2022.

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)		2023		2022
(Thousands)					
Gas distribution plant	5-75	$	1,116,388	$	1,063,928
Software	3-10		46,002		42,924
Land			1,618		1,618
Building and improvements	35-50		40,376		37,848
Other plant	45-90		66,880		68,195
Total Utility Plant in Service			**1,271,264**		**1,214,513**
Total accumulated depreciation			(424,187)		(399,929)
Total Net Utility Plant in Service			**847,077**		**814,584**
Construction work in progress			21,284		15,370
Total Utility Plant		**$**	**868,361**	**$**	**829,954**

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.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

(Thousands)		2023		2022
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	8,840	$	8,605
Income taxes paid, net	$	3,340	$	14,301

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $0.4 million in 2023 and in 2022. Accrued liabilities for utility plant additions were $14.9 million and $7.5 million as of December 31, 2023 and 2022, respectively.

***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 $30.6 million for 2023 and $49.2 million for 2022, and are shown net of an allowance for credit losses at December 31 of $6.0 million for 2023 and $7.0 million for 2022. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $8.5 million in 2023 and $9.0 million in 2022.

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. We 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.

There were no government grants recorded as of December 31, 2023 and 2022.

Deferred income: Apart from government grants, we occasionally receive payments from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such payments 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, 2023 and 2022.

Years Ended December 31,	2023	2022
(Thousands)		
ARO, beginning of year	$ 6,279	$ 6,398
Liabilities settled during the year	(461)	(447)
Accretion expenses	322	328
ARO, end of year	**$ 6,140**	**$ 6,279**

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. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the CNG Pension Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Effective April 1, 2022, the amortization period for prior service cost changes for CNG Pension Plan B was updated from average remaining service to future expected lifetime as the plan was frozen to future accruals. Effective December 10, 2022, the amortization period for prior service cost changes for the CNG

Retirement Plan was updated from average remaining service to future expected lifetime as the plan was frozen to future accruals. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans in excess of 10% of the greater of periodic benefit obligation or market-related value of assets on a straight-line basis over future working lifetime. Effective March 31, 2022, the amortization period for the CNG Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Effective April 1, 2022, the amortization period for CNG Pension Plan B was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals. Effective December 10, 2022, the amortization period for the CNG Retirement Plan was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals. 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: In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax (“CAMT”) of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The CAMT and other various applicable provisions of the IRA are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year, as well as on anticipated guidance from the U.S. Department of Treasury.

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 was $2.8 million and $4.7 million at December 31, 2023 and 2022, 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 regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit 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 had no intra-entity transfers of assets other than inventory during the years ended December 31, 2023 and 2022.

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.

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.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2023, that are expected to have a material impact on CNG’s financial statements.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on CNG’s financial statements.

(a) Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance to enhance income tax disclosures. The two primary enhancements relate to disaggregation of the annual disclosures for the effective tax rate reconciliation and income taxes paid. For the rate reconciliation, it requires additional disaggregation of information in a tabular format using both percentages and amounts broken out into specific categories (e.g., state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, and changes in unrecognized tax benefits). For income taxes paid, it requires disaggregation by jurisdiction (e.g., federal, state and foreign). We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

***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.

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 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. Given the expiration of the rate plan, CNG has been operating under the 2019 approved rate schedules for the years ended December 31, 2023 and 2022.

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.

On November 3, 2023, CNG filed a distribution revenue requirement case proposing a one-year rate plan commencing November 1, 2024 through October 31, 2025. The filing was based on a test year ending December 31, 2023. CNG requested that PURA approve new distribution rates to recover an increase in revenue requirements of approximately $19.8 million. CNG's Rate Plan also included several measures to moderate the impact of the proposed rate update for all customers, including, the adoption of a low-income discount rate and seeks to maintain its current revenue decoupling and earning sharing mechanisms.

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 and Algonquin 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 Ontario, Canada.

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 $73.4 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.

Regulatory assets at December 31, 2023 and 2022 consisted of:

As of December 31,	**2023**	**2022**
(Thousands)		
Deferred purchased gas	$ 6,579	$ 24,428
Pension and other postretirement benefit plan	61,337	52,574
Revenue decoupling mechanism	26,524	20,311
System expansion reconciliation	9,535	8,871
Unfunded future income taxes	10,473	6,375
Other	11,518	7,692
Total regulatory assets	**125,966**	**120,251**
Less: current portion	50,255	57,875
Total non-current regulatory assets	**$ 75,711**	**$ 62,376**

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.

Pension and other postretirement benefit plan represents 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.

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

System expansion reconciliation represents expenses not covered by system expansion rates related to expanding the natural gas system and converting customers to natural gas.

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 Distribution Integrity Management Program and Environmental Defense Fund legal fees.

Regulatory liabilities at December 31, 2023 and 2022 consisted of:

As of December 31,	2023	2022
(Thousands)		
Asset removal costs	$ 265,552	$ 247,523
Asset retirement obligation	10,514	10,409
Hardship programs	2,558	5,018
Non-firm margin sharing credits	17,107	14,150
Rate credits	5,000	6,250
Tax reform	12,845	13,167
Other	1,346	5,914
Total regulatory liabilities	**314,922**	**302,431**
Less: current portion	5,386	5,230
Total non-current regulatory liabilities	**$ 309,536**	**$ 297,201**

Asset removal costs 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.

Hardship programs represent customer accounts deferred for recovery to the extent they exceed the amount in rates.

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects.

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.

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, 2023 and 2022 are as follows:

Years Ended December 31,	**2023**	**2022**
(Thousands)		
Regulated operations – natural gas	$ 406,904	$ 509,967
Other (a)	910	12
Revenue from contracts with customers	**407,814**	**509,979**
Alternative revenue programs	19,712	11,850
Other revenue	1,173	1,844
Total operating revenues	**$ 428,699**	**$ 523,673**

(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.

We had no impairment of goodwill in 2023 and 2022 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2023 or 2022 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, 2023 and 2022, with no accumulated impairment losses and no changes during 2023 and 2022.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,	2023	2022
(Thousands)		
Current		
Federal	$ 435	$ 6,589
State	826	1,190
Current taxes charged to expense	**1,261**	**7,779**
Deferred		
Federal	6,977	2,258
State	11	1,169
Deferred taxes charged to expense	**6,988**	**3,427**
Total Income Tax Expense	**$ 8,249**	**$ 11,206**

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, 2023 and 2022 consisted of:

Years Ended December 31,	2023	2022
(Thousands)		
Tax expense at federal statutory rate	$ 7,862	$ 9,517
Tax return related adjustments	—	15
State taxes, net of federal income tax	661	1,864
Other, net	(274)	(190)
Total Income Tax Expense	**$ 8,249**	**$ 11,206**

Income tax expense for the year ended December 31, 2023 was $0.4 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state income taxes, which are partially offset by tax benefits from Excess Accumulated Deferred Income Tax (ADIT) amortization and AFUDC flow through adjustments. This resulted in an effective tax rate of 22.0%. Income tax expense for the year ended December 31, 2022 was $1.7 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state income taxes, which were partially offset by tax benefits from Excess ADIT amortization and AFUDC flow through adjustments. This resulted in an effective tax rate of 24.7%.

Deferred tax assets and liabilities as of December 31, 2023 and 2022 consisted of:

December 31,		**2023**		**2022**
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
CT credit carryforward	$	(7,397)	$	(6,412)
Valuation allowance - State Credits		4,139		1,304
Deferred tax liability on 2017 Tax Act remeasurement		(3,459)		(3,482)
Property related		51,294		47,633
Unfunded future income taxes		2,761		1,629
Goodwill		6,196		5,727
Pension (net)		(240)		(1,288)
Other		2,817		(387)
Total Non-current Deferred Income Tax Liabilities	**$**	**56,111**	**$**	**44,724**
Deferred tax assets	$	11,096	$	11,569
Deferred tax liabilities		67,207		56,293
Net Accumulated Deferred Income Tax Liabilities	**$**	**56,111**	**$**	**44,724**

As of December 31, 2023, CNG had a state net credit carry forward of $7.4 million and a net state net operating loss carry forward of $1.7 million. As of December 31, 2022, CNG had a state net credit carry forward of $6.4 million and a net state net operating loss carry forward of $1.1 million. CNG's state tax credit carry forwards will begin to expire for the 2023 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. At December 31, 2023, CNG has recorded a valuation allowance of $4.1 million against its CT tax credits. The company also recorded a regulatory asset of $5.7 million to recover the associated tax expense of the valuation allowance against the state credits whose tax benefits were previously shared with customers. As of December 31, 2022, CNG had recorded a valuation allowance on its state credit carryforwards of $1.3 million. The company also recorded a regulatory asset of $1.8 million to recover the associated tax expense of the valuation allowance against the state credits whose tax benefits were previously shared with customers.

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, 2023 and 2022, 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, 2023 or 2022.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2023 or 2022.

Note 7. Non-current Debt

Long-term debt as of December 31, 2023 and 2022 consisted of:

As of December 31,		**2023**		**2022**	
(Thousands, except interest rates)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2028-2049	$ 245,000	2.02%-6.66%	$ 190,000	2.02%-6.66%
Unamortized debt issuance costs and discount		(1,077)		(928)	
Total Debt		**243,923**		**189,072**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 243,923**		**$ 189,072**	

On December 13, 2023, CNG issued $36 million aggregate principal amount of Senior Series unsecured debt maturing in 2032 at an interest rate of 6.20% and $19 million aggregate principal amount of Senior Series unsecured debt maturing in 2038 at an interest rate of 6.49%.

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

2024	**2025**	**2026**	**2027**	**2028**	**Total**
(Thousands)					
$ —	$ —	$ —	$ —	$ 25,000	$ 25,000

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2023 and 2022.

Note 8. Bank Loans and Other Borrowings

CNG had no notes payable at December 31, 2023 and $25.5 million at December 31, 2022. 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 outstanding debt under this agreement at December 31, 2023 and $25.5 million outstanding under this agreement at December 31, 2022.

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 no debt outstanding under this agreement at December 31, 2023 and December 31, 2022.

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, 2023 and 2022.

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 0.35 to 1.00 at December 31, 2023. We are not in default as of December 31, 2023.

Note 9. Redeemable Preferred Stock

At December 31, 2023 and 2022, our redeemable preferred stock was:

				Amount (Thousands)	
Series	**Par Value per Share**	**Redemption Price per Share**	**Shares Authorized and Outstanding(1)**	**2023**	**2022**
CNG, 8% Non-callable	$ 3.125	$ —	108,706	$ 340	$ 340
Total				**$ 340**	**$ 340**

(1) At December 31, 2023 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 9 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,	2023	2022
(Thousands)		
Lease cost		
Operating lease cost	$ 11	$ 291
Short-term lease cost	88	38
Variable lease cost	14	44
Total lease cost	**$ 113**	**$ 373**

Balance sheet and other information for the years ended December 31, 2023 and 2022 was as follows:

As of December 31,	2023	2022
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 2,746	$ 2,432
Operating lease liabilities, current	429	177
Operating lease liabilities, long-term	2,364	2,323
Total operating lease liabilities	**$ 2,793**	**$ 2,500**
Weighted-average Remaining Lease Term (years)		
Operating leases	7.14	2.20
Weighted-average Discount Rate		
Operating leases	3.66 %	3.53 %

For the years ended December 31, 2023 and 2022, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,	2023	2022
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 410	$ 305
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 689	$ 2,445

As of December 31, 2023, maturities of lease liabilities were as follows:

		Operating Leases
(Thousands)		
Year ending December 31,		
2024	$	444
2025		445
2026		333
2027		329
2028		324
Thereafter		1,327
Total lease payments		**3,202**
Less: imputed interest		(409)
Total	**$**	**2,793**

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, 2023 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, 2023, 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 $246 million and $178 million as of December 31, 2023 and 2022, 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, 2023 and 2022 consist of:

Description	Total	(Level 1)	(Level 2)	(Level 3)
(Thousands)				
2023				
Assets				
Noncurrent investments	$ 727	$ 727	$ —	$ —
Total	**$ 727**	**$ 727**	**$ —**	**$ —**
2022				
Assets				
Noncurrent investments	$ 764	$ 764	$ —	$ —
Total	**$ 764**	**$ 764**	$ —	$ —

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2023 and 2022. 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 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 $3.2 million for 2023 and $2.2 million for 2022.

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 $1.0 million at December 31, 2023 and 2022.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 201,847**	**$ 295,866**	**$ 17,397**	**$ 17,528**
Service cost	282	3,827	62	120
Interest cost	10,120	9,340	853	436
Actuarial (gain) loss	15,529	(65,217)	3,755	1,416
Curtailments/Settlements	—	(29,024)	—	—
Benefits paid	(17,704)	(12,945)	(1,869)	(2,103)
Benefit obligation as of December 31,	**$ 210,074**	**$ 201,847**	**$ 20,198**	**$ 17,397**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 154,490**	**$ 229,768**	**$ 11,325**	**$ 12,237**
Actual return on plan assets	18,895	(46,939)	453	(762)
Employer contributions	—	855	1,869	1,953
Curtailments/settlements	—	(16,249)	—	—
Benefits paid	(17,704)	(12,945)	(1,869)	(2,103)
Fair value of plan assets at December 31,	**$ 155,681**	**$ 154,490**	**$ 11,778**	**$ 11,325**
Funded status at December 31,	**$ (54,393)**	**$ (47,357)**	**$ (8,420)**	**$ (6,072)**

During 2023, the pension benefit obligation had an actuarial loss of $15.5 million, primarily due to $9.8 million loss from decrease in discount rate. During 2023, the postretirement benefit obligation had an actuarial loss of $3.8 million. This loss was primarily driven by $2.6 million loss from assumption changes in health care trend rates and $0.8 million loss from decrease in discount rates.

During 2022, the pension benefit obligation had an actuarial gain of $65.2 million, primarily due to a $57.4 million gain from increases in discount rates. The pension benefit obligation had a reduction of $16.2 million from settlements and $12.8 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Non-current liabilities	$ (54,393)	$ (47,357)	$ (8,420)	$ (6,072)

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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Net loss (gain)	$ 17,623	$ 10,783	$ 4,709	$ 1,070

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $210.1 million and $201.8 million as of December 31, 2023 and 2022. Our postretirement benefits were partially funded at December 31, 2023 and 2022.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2023 and 2022. 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,	**2023**	**2022**
(Thousands)		
Projected benefit obligation	$ 210,074	$ 201,847
Accumulated benefit obligation	$ 210,074	$ 201,847
Fair value of plan assets	$ 155,681	$ 154,490

As of December 31, 2023 and 2022, 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, 2023 and 2022 consisted of:

For the years ended December 31,	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 282	$ 3,827	$ 62	$ 120
Interest cost	10,120	9,340	853	436
Expected return on plan assets	(10,283)	(14,469)	(447)	(419)
Amortization of prior service cost	—	—	—	195
Curtailment charge	—	(1,774)	—	—
Settlement charge	—	1,237	—	—
Amortization of net loss (gain)	77	738	110	(169)
Net Periodic Benefit Cost	**$ 196**	**$ (1,101)**	**$ 578**	**$ 163**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net (gain) loss	$ 6,917	$ (3,809)	$ 3,749	$ 2,596
Settlements	—	(1,237)	—	—
Amortization of net (loss) gain	(77)	(738)	(110)	169
Effect of curtailments on gain	—	(11,001)	—	—
Amortization of prior service cost	—	—	—	(195)
Total Other Changes	**6,840**	**(16,785)**	**3,639**	**2,570**
Total Recognized	**$ 7,036**	**$ (17,886)**	**$ 4,217**	**$ 2,733**

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, 2023 and 2022 consisted of:

	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
Discount rate	4.75%	5.17% / 5.25%	4.69%	5.13%
Rate of compensation increase	N/A	N/A	N/A	N/A
Interest crediting rate	3.47%	4.48%	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, 2023 and 2022 consisted of:

Years Ended December 31,	Pension Benefits 2023	2022	Postretirement Benefits 2023	2022
Discount rate	5.21 %	2.85% - 5.02%	5.13 %	2.61 %
Expected long-term return on plan assets	7.50 %	7.00 %	3.95 %	3.42 %
Rate of compensation increase (Union/Non-Union)	N/A	3.50% / 3.00% / 2.90%	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. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans in excess of 10% of the greater of periodic benefit obligation or market-related value of assets on a straight-line basis over future working lifetime. Effective March 31, 2022, the amortization period for the CNG Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Effective April 1, 2022, the amortization period for CNG Pension Plan B was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals. Effective December 10, 2022, the amortization period for the CNG Retirement Plan was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2023 and 2022 consisted of:

As of December 31,	2023	2022
Health care cost trend rate assumed for next year	8.10% / 8.60%	6.25% / 7.00%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50% / 4.50%	4.50% / 4.50%
Year that the rate reaches the ultimate trend rate	2031 / 2032	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 $6.2 million to our pension plans during 2024. We do not expect to contribute to our other postretirement benefit plans during 2024.

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, 2023 consisted of:

(Thousands)		Pension Benefits		Postretirement Benefits		Medicare Act Subsidy Receipts
2024	$	15,800	$	1,712	$	152
2025	$	17,480	$	1,610	$	157
2026	$	16,455	$	1,581	$	160
2027	$	16,328	$	1,526	$	165
2028	$	16,860	$	1,484	$	172
2029 - 2033	$	79,580	$	6,772	$	972

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 15%-70% for Return-Seeking assets and 30%-85% for Liability-Hedging assets. Return-Seeking assets include investments in domestic, international and emerging equity, 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, 2023, consisted of:

As of December 31, 2023		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 3,710	$ 125	$ 3,585	$ —
U.S. government securities	16,629	16,629	—	—
Common stocks	7,295	7,295	—	—
Registered investment companies	8,245	8,245	—	—
Corporate bonds	40,943	—	40,943	—
Common collective trusts	59,627	—	59,627	—
Other, principally annuity, fixed income	(5,122)	(3)	(5,119)	—
	$ 131,327	**$ 32,291**	**$ 99,036**	**$ —**
Other investments measured at net asset value	24,354			
Total	**$ 155,681**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 5,373	$ 17	$ 5,356	$ —
U.S. government securities	8,190	8,190	—	—
Common stocks	6,539	6,539	—	—
Registered investment companies	7,665	7,665	—	—
Corporate bonds	40,769	—	40,769	—
Preferred stocks	43	43	—	—
Common collective trusts	55,867	—	55,867	—
Other, principally annuity, fixed income	545	—	545	—
	$ 124,991	**$ 22,454**	**$ 102,537**	**$ —**
Other investments measured at net asset value	29,499			
Total	**$ 154,490**			

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 26% 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 of increasing the projected expected return, while mitigating 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, 2023, consisted of:

As of December 31, 2023		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 109	$ 2	$ 107	$ —
U.S. government securities	325	325	—	—
Common stocks	122	122	—	—
Registered investment companies	191	191	—	—
Corporate bonds	771	—	771	—
Common collective trusts	1,271	—	1,271	—
Other, principally annuity, fixed income	8,558	—	8,558	—
	$ 11,347	**$ 640**	**$ 10,707**	**$ —**
Other investments measured at net asset value	431			
Total	**$ 11,778**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 261	$ —	$ 261	$ —
U.S. government securities	147	147	—	—
Common stocks	108	108	—	—
Registered investment companies	172	172	—	—
Corporate bonds	665	—	665	—
Preferred stocks	1	1	—	—
Common collective trusts	1,063	—	1,063	—
Other, principally annuity, fixed income	8,465	—	8,465	—
	$ 10,882	**$ 428**	**$ 10,454**	**$ —**
Other investments measured at net asset value	443			
Total	**$ 11,325**			

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, 2023 and 2022.

Note 14. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Allowance for funds used during construction	$	2,026	$	1,428
Carrying costs on regulatory assets		753		850
Miscellaneous		43		66
Total other income	**$**	**2,822**	**$**	**2,344**
Pension non-service components	$	2,403	$	(3,641)
Miscellaneous		(1,439)		(2,182)
Total other (deductions) income, net	**$**	**964**	**$**	**(5,823)**

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 $20.3 million and $24.3 million for the years ended December 31, 2023 and 2022, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $0.9 million in 2023 and $0.5 million in 2022. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by CNG to AGR and its subsidiaries were approximately $4.7 million for 2023 and $4.5 million for 2022. 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 $19.1 million at December 31, 2023 and $19.9 million at December 31, 2022 is mostly payable to UIL Holdings Corporation. The balance in accounts receivable from affiliates of $0.2 million at December 31, 2023 and $0.5 million at December 31, 2022 is mostly receivable from SCG.

There were $26.6 million in notes receivable from NYSEG and BGC at December 31, 2023 and no notes receivable at December 31, 2022. 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 29, 2024, 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, 2023 and 2022

The Southern Connecticut Gas Company

Index

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

Independent Auditors' Report

The Stockholder and 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, 2023 and 2022, 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, 2023 and 2022, 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 available to be 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 29, 2024

The Southern Connecticut Gas Company
Consolidated Statements of Income

Years Ended December 31,		2023		2022
(Thousands)				
Operating Revenues	$	**426,092**	$	**515,861**
Operating Expenses				
Natural gas purchased		190,283		274,609
Operations and maintenance		101,292		93,370
Depreciation and amortization		42,412		38,835
Taxes other than income taxes, net		35,557		35,431
Total Operating Expenses		**369,544**		**442,245**
Operating Income		**56,548**		**73,616**
Other income		2,639		2,647
Other deductions		(2,376)		(12,172)
Interest expense, net of capitalization		(18,227)		(17,709)
Income Before Income Tax		**38,584**		**46,382**
Income tax expense		6,904		3,403
Net Income		**31,680**		**42,979**
Less: net income attributable to noncontrolling interest		2,673		3,462
Net Income Attributable to SCG	$	**29,007**	$	**39,517**

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,		2023		2022
(Thousands)				
Net Income	$	**29,007**	$	**39,517**
Other Comprehensive Income (Loss), Net of Tax				
Amortization of pension cost for non-qualified plans and current year actuarial gain (loss), net of income tax benefit of ($57) for 2023 and income tax expense of $409 for 2022		(154)		1,111
Total Other Comprehensive Income (Loss), Net of Tax		**(154)**		**1,111**
Comprehensive Income		**28,853**		**40,628**
Less: Comprehensive income attributable to noncontrolling interest		2,673		3,462
Comprehensive Income Attributable to SCG	$	**26,180**	$	**37,166**

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

The Southern Connecticut Gas Company
Consolidated Balance Sheets

As of December 31,	2023	2022
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 380	$ 1,259
Accounts receivable and unbilled revenues, net	103,015	133,397
Accounts receivable from affiliates	648	1,645
Notes receivable from affiliates	15,259	1,660
Gas in storage	45,886	57,789
Materials and supplies	4,400	4,002
Other current assets	4,047	1,106
Regulatory assets	48,064	48,145
Total Current Assets	**221,699**	**249,003**
Utility plant, at original cost	1,435,400	1,340,472
Less accumulated depreciation	(403,611)	(375,637)
Net Utility Plant in Service	**1,031,789**	**964,835**
Construction work in progress	26,905	20,303
Total Utility Plant	**1,058,694**	**985,138**
Operating lease right-of-use assets	11,256	10,418
Other property and investments	10,396	9,372
Regulatory and Other Assets		
Regulatory assets	163,696	159,846
Goodwill	134,931	134,931
Other	372	372
Total Regulatory and Other Assets	**298,999**	**295,149**
Total Assets	**$ 1,601,044**	**$ 1,549,080**

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

The Southern Connecticut Gas Company
Consolidated Balance Sheets

As of December 31,	2023	2022
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 2,087	$ 24,600
Accounts payable and accrued liabilities	71,892	96,451
Accounts payable to affiliates	20,927	19,655
Interest accrued	4,096	3,881
Taxes accrued	12,324	11,493
Operating lease liabilities	904	781
Regulatory liabilities	6,279	14,843
Other	21,794	19,792
Total Current Liabilities	**140,303**	**191,496**
Regulatory and Other Liabilities		
Regulatory liabilities	245,911	232,557
Other Non-current Liabilities		
Deferred income taxes	109,708	103,303
Pension and other postretirement	48,122	48,768
Operating lease liabilities	11,364	10,484
Asset retirement obligation	12,907	12,785
Environmental remediation costs	60,624	60,661
Other	7,071	5,007
Total Regulatory and Other Liabilities	**249,796**	**241,008**
Non-current debt	364,471	304,982
Total Liabilities	**1,000,481**	**970,043**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($13.33 par value, 2,650,000 shares authorized and 1,407,072 shares outstanding at December 31, 2023 and 2022)	18,761	18,761
Additional paid-in capital	472,737	462,737
Retained earnings	71,322	62,315
Accumulated other comprehensive loss	(5,370)	(5,216)
Total SCG Common Stock Equity	**557,450**	**538,597**
Noncontrolling interest	43,113	40,440
Total Equity	**600,563**	**579,037**
Total Liabilities and Equity	**$ 1,601,044**	**$ 1,549,080**

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,	2023	2022
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 31,680**	**$ 42,979**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	42,412	38,835
Regulatory assets/liabilities amortization	13,360	14,240
Regulatory assets/liabilities carrying cost	3,996	3,493
Amortization of debt issuance costs	(195)	(437)
Deferred taxes	1,928	(1,046)
Pension cost	2,274	1,824
Accretion expenses	656	649
Gain on disposal of assets	(39)	—
Other non-cash items	(74)	3,161
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	31,379	(29,782)
Inventories	11,505	(24,184)
Accounts payable, to affiliates, and accrued liabilities	(35,035)	20,697
Taxes accrued	831	(18,884)
Other assets/liabilities	5,496	10,499
Regulatory assets/liabilities	(26,775)	(31,928)
Net Cash Provided by Operating Activities	**83,399**	**30,116**
Cash Flow from Investing Activities:		
Capital expenditures	(100,910)	(96,005)
Contributions in aid of construction	2,914	3,145
Proceeds from sale of utility plant	181	74
Notes receivable from affiliates	(13,599)	27,296
Net Cash Used in Investing Activities	**(111,414)**	**(65,490)**
Cash Flow from Financing Activities:		
Non-current debt issuance	59,649	—
Notes payable to affiliates	(22,513)	21,020
Capital contributions	10,000	50,000
Contributions from noncontrolling interest	—	708
Dividends paid	(20,000)	(30,000)
Payment of noncontrolling interest dividend	—	(5,568)
Net Cash Provided by Financing Activities	**27,136**	**36,160**
Net (Decrease) Increase in Cash and Cash Equivalents	**(879)**	**786**
Cash and Cash Equivalents, Beginning of Period	**1,259**	**473**
Cash and Cash Equivalents, End of Period	**$ 380**	**$ 1,259**

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, 2021	**1,407,072**	**$ 18,761**	**$ 412,737**	**$ 52,798**	**$ (6,327)**	**$ 41,838**	**$ 519,807**
Net income	—	—	—	39,517	—	—	39,517
Other comprehensive income, net of tax	—	—	—	—	1,111	—	1,111
Comprehensive income	—						40,628
Net income attributable to noncontrolling interest	—	—	—	—	—	3,462	3,462
Payment of noncontrolling interest dividend	—	—	—	—	—	(5,568)	(5,568)
Contributions from noncontrolling interest	—	—	—	—	—	708	708
Payment of common stock dividend	—	—	—	(30,000)	—	—	(30,000)
Capital contributions	—	—	50,000	—	—	—	50,000
Balance, December 31, 2022	**1,407,072**	**18,761**	**462,737**	**62,315**	**(5,216)**	**40,440**	**579,037**
Net income	—	—	—	29,007	—	—	29,007
Other comprehensive loss, net of tax	—	—	—	—	(154)	—	(154)
Comprehensive income							28,853
Net income attributable to noncontrolling interest	—	—	—	—	—	2,673	2,673
Payment of common stock dividend	—	—	—	(20,000)	—	—	(20,000)
Capital contributions	—	—	10,000	—	—	—	10,000
Balance, December 31, 2023	**1,407,072**	**$ 18,761**	**$ 472,737**	**$ 71,322**	**$ (5,370)**	**$ 43,113**	**$ 600,563**

(*) 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 209,000 customers as of December 31, 2023, 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 81.6% 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 $48.3 million and income of $2.7 million as of and for the year ended December 31, 2023. 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,		2023		2022
(Thousands)				
Assets				
Current assets	$	18,914	$	13,076
Long-term assets		29,386		28,493
Total Assets		**48,300**		**41,569**
Liabilities				
Current liabilities		4,834		1,129
Long-term liabilities		353		—
Total Liabilities	**$**	**5,187**	**$**	**1,129**

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. The accounting records of SCG are also maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC).

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 primarily 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 2.8% of average depreciable property for both 2023 and 2022. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 10 years. Depreciation expense was $38.4 million in 2023 and $35.3 million in 2022. Amortization of capitalized software was $4.0 million in 2023 and $3.5 million in 2022.

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)	2023	2022
(Thousands)			
Gas distribution plant	6-78	$ 1,275,329	$ 1,198,454
Software	3-10	59,497	55,619
Land	N/A	7,663	7,658
Building and improvements	40-50	40,424	29,939
VIE	10-50	47,104	43,419
Other plant	25-39	5,383	5,383
Total Utility Plant in Service		**1,435,400**	**1,340,472**
Total accumulated depreciation		(403,611)	(375,637)
Total Net Utility Plant in Service		**1,031,789**	**964,835**
Construction work in progress		26,905	20,303
Total Utility Plant		**$ 1,058,694**	**$ 985,138**

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.

Notes to Consolidated Financial Statements

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.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2023		2022
(Thousands)				
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	12,904	$	13,204
Income taxes paid, net	$	3,511	$	23,224

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 $0.9 million in 2023 and in $0.7 million in 2022. Accrued liabilities for utility plant additions were $25.0 million and $14.2 million as of December 31, 2023 and 2022, respectively.

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 $24.5 million for 2023 and $33.3 million for 2022, and are shown net of an allowance for credit losses at December 31 of $6.8 million for 2023 and $8.8 million for 2022. Trade receivable do not bear interest, although late fees may be assessed. Credit loss expense was $5.3 million in 2023 and $6.5 million in 2022.

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. We 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.

There were no government grants recorded as of December 31, 2023 and 2022.

Deferred income: Apart from government grants, we occasionally receive payments from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such payments 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, 2023 and 2022.

Years ended December 31,		**2023**		**2022**
(Thousands)				
ARO, beginning of year	$	12,785	$	12,654
Liabilities settled during the year		(533)		(518)
Accretion expense		655		649
ARO, end of year	**$**	**12,907**	**$**	**12,785**

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 2048.

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 (PBO). 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. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the SCG Salaried Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. We amortize unrecognized actuarial gains and losses in excess of 10% of the greater of PBO or market-related value of assets (MRVA) related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the SCG Salaried Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. 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**:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The CAMT and other various applicable provisions of the IRS are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year, as well as on anticipated guidance from the U.S. Department of Treasury.

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 is $7.7 million and $5.5 million at December 31, 2023 and 2022, 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 regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit 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, 2023 and 2022.

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. We consider the effect of the alternative minimum tax system in determining the need for a valuation allowance for deferred taxes. 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.

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.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2023 that are expected to have a material impact on SCG’s consolidated financial statements.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on SCG's consolidated financial statements.

(a) Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance to enhance income tax disclosures. The two primary enhancements relate to disaggregation of the annual disclosures for the effective tax rate reconciliation and income taxes paid. For the rate reconciliation, it requires additional disaggregation of information in a tabular format using both percentages and amounts broken out into specific categories (e.g., state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, and changes in unrecognized tax benefits). For income taxes paid, it requires disaggregation by jurisdiction (e.g., federal, state and foreign). We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

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.

Union collective bargaining agreements: Approximately 74% of our employees are covered by collective bargaining agreements. We have 95% of the collective bargaining agreements expiring during 2024.

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. Given the expiration of the rate plan, SCG has been operating under the 2018 approved rate schedules for the years ended December 31, 2023 and 2022

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.

On November 3, 2023, SCG filed a distribution revenue requirement case proposing a one-year rate plan commencing November 1, 2024 through October 31, 2025. The filing was based on a test year ending December 31, 2022. SCG requested approval of new distribution rates to recover an increase in revenue requirements of approximately $40.6 million. SCG's Rate Plan also included several measures to moderate the impact of the proposed rate update for all customers, including, the adoption of a low-income discount rate and seeks to maintain its current revenue decoupling and earning sharing mechanisms. We cannot predict the outcome of this matter.

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 Ontario, Canada.

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 $132.0 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 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.

Regulatory assets at December 31, 2023 and 2022 consisted of:

December 31,	**2023**	**2022**
(Thousands)		
Asset retirement obligation	$ 4,064	$ 3,893
Debt premium	2,921	3,514
Deferred purchased gas	280	17,214
Distribution integrity management program	19,312	10,161
Environmental remediation costs	69,111	67,366
Pension and other postretirement benefits	59,934	62,653
Revenue decoupling mechanism	14,532	7,304
System expansion	12,960	12,464
Unfunded future income taxes	22,703	18,169
Other	5,943	5,253
Total regulatory assets	**211,760**	**207,991**
Less: current portion	48,064	48,145
Total non-current regulatory assets	**$ 163,696**	**$ 159,846**

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.

Distribution integrity management program (DIMP) represents deferred expenses related to pipeline replacement for cast iron and bare steel mains and services. Balances at the end of each rate year are normally received/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.

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.

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.

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 deferred credit card fees, Environmental defense fund (EDF) legal costs and COVID-19 deferrals.

Regulatory liabilities at December 31, 2023 and 2022 consisted of:

December 31,	2023	2022
(Thousands)		
Asset removal obligation	$ 122,722	$ 119,675
Low income program	4,561	13,824
Non-firm margin sharing credits	17,363	13,335
Pension and other postretirement benefits	5,349	5,256
Rate credits	3,000	3,750
Tax reform	79,816	68,330
Unfunded future income taxes	10,907	13,578
Other	8,472	9,652
Total regulatory liabilities	**252,190**	**247,400**
Less: current portion	6,279	14,843
Total non-current regulatory liabilities	**$ 245,911**	**$ 232,557**

Asset 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 reform 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.

Other includes items such as Geographical information system (GIS) data conversion and energy efficiency programs.

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, 2023 and 2022 are as follows:

Years Ended December 31,	**2023**	**2022**
(Thousands)		
Regulated operations – natural gas	$ 406,164	$ 506,201
Other(a)	873	179
Revenue from contracts with customers	**407,037**	**506,380**
Leasing revenue	2	2
Alternative revenue programs	15,217	4,205
Other revenue	3,836	5,274
Total operating revenues	**$ 426,092**	**$ 515,861**

(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.

We had no impairment of goodwill in 2023 and 2022 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2023 or 2022 that required us to update the assessment.

The carrying amount of goodwill was $134.9 million at both December 31, 2023 and 2022, with no accumulated impairment losses and no changes during 2023 and 2022.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,	**2023**	**2022**
(Thousands)		
Current		
Federal	$ (1,920)	$ 6,199
State	6,896	(1,750)
Current taxes charged to expense	**4,976**	**4,449**
Deferred		
Federal	9,593	4,215
State	(7,665)	(5,261)
Deferred taxes charged to expense (benefit)	**1,928**	**(1,046)**
Total Income Tax Expense	**$ 6,904**	**$ 3,403**

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, 2023 and 2022, respectively, consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Tax expense at statutory rate	$	8,103	$	9,740
State tax expense, net of federal income tax benefit		(607)		(5,539)
Variable interest entity		(736)		(953)
Other, net		144		155
Total Income Tax Expense	**$**	**6,904**	**$**	**3,403**

Income tax expense for the year ended December 31, 2023 was $1.2 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to state income taxes and variable interest entity adjustments. This resulted in an effective tax rate of 17.9%. Income tax expense for the year ended December 31, 2022 was $6.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to state income taxes and variable interest entity adjustments. This resulted in an effective tax rate of 7.3%.

Deferred tax assets and liabilities as of December 31, 2023 and 2022 consisted of:

December 31,		2023		2022
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	133,945	$	117,864
Unfunded future income taxes		3,101		1,048
Valuation allowance - state credits		13,675		12,074
Federal and state tax credits		(13,883)		(12,487)
Goodwill		23,571		21,780
2017 Tax Act remeasurement		(21,491)		(18,398)
Federal and state NOL’s		(36,415)		(20,095)
Post-retirement benefits, net		1,645		192
Other		5,560		1,325
Total Non-current Deferred Income Tax Liabilities	**$**	**109,708**	**$**	**103,303**
Deferred tax assets	$	71,789	$	50,980
Deferred tax liabilities		181,497		154,283
Net Accumulated Deferred Income Tax Liabilities	**$**	**109,708**	**$**	**103,303**

SCG has federal net operating losses of $27.7 million, net state net operating losses of $8.6 million and net state credit carryforward of $13.9 million for the year ended December 31, 2023. SCG had federal net operating losses of $17.1 million, net state net operating losses of $3.0 million and net state credit carryforward of $12.5 million for the year ended December 31, 2022.

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, 2023, SCG had recorded a valuation allowance on its state tax credit carryforwards of $13.7 million. The company has also recorded a regulatory asset of $21.7 million to recover the associated tax expense of the valuation allowance against the state credits, whose tax benefits were previously shared with customers. As of December 31, 2022, SCG had recorded a valuation allowance on its state credit carryforwards of $12.1 million. The company has also recorded a regulatory asset of $17.5 million to recover the associated tax expense of the valuation allowance against the state credits, whose tax benefits were previously shared with customers

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, 2023 and 2022, 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, 2023 and 2022.

Note 7. Long-term Debt

Long-term debt as of December 31, 2023 and 2022 consisted of:

As of December 31,		**2023**		**2022**	
(Thousands, except interest rates)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds (a)	2025-2049	$ 364,000	1.87% - 7.95%	$ 304,000	1.87% - 7.95%
Unamortized debt issuance premium, net		471		982	
Total Debt		**364,471**		**304,982**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 364,471**		**$ 304,982**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of SCG's properties.

On December 13, 2023, SCG issued $30 million of first mortgage private bonds maturing in 2034 at an interest rate of 6.04% and 30 million of first mortgage private bonds maturing in 2038 at an interest rate of 6.24% .

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

2024	**2025**	**2026**	**2027**	**2028**	**Total**
(Thousands)					
$ —	$ 25,000	$ 15,000	$ —	$ 14,000	$ 54,000

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, 2023 and 2022, SCG was in compliance with long-term debt covenants.

Note 8. Bank Loans and Other Borrowings

Notes payable balances totaled $2.1 million and $24.6 million as of December 31, 2023 and 2022, 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, 2023 and $24.4 million outstanding under this agreement at December 31, 2022.

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, 2023 and 2022.

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, 2023 and 2022.

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 0.38 to 1.00 at December 31, 2023. We are not in default as of December 31, 2023.

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, 2023 and 2022 TPS had $2.1 million and $0.2 million, respectively, outstanding under its agreement. CNE did not have any amounts outstanding under its agreement as of December 31, 2023 and 2022.

Note 9. Preferred Stock

At December 31, 2023, 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.

Notes to Consolidated Financial Statements

Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. As of December 31, 2023 and 2022, 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 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,	2023	2022
(Thousands)		
Lease cost		
Operating lease cost	$ 1,160	$ 1,233
Short-term lease cost	224	143
Variable lease cost	529	432
Total lease cost	**$ 1,913**	**$ 1,808**

Consolidated balance sheet and other information for the years ended December 31, 2023 and 2022 was as follows:

As of December 31,	2023	2022
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right of use assets	$ 11,256	$ 10,418
Operating lease liabilities, current	904	781
Operating lease liabilities, long-term	11,364	10,484
Total operating lease liabilities	$ 12,268	$ 11,265
Weighted-average Remaining Lease Term (years):		
Operating leases	9.31	10.87
Weighted-average Discount Rate:		
Operating leases	4.18 %	3.57 %

Supplemental consolidated cash flows information related to leases was as follows:

Years Ended December 31,	2023	2022
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,168	$ 792
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 1,735	$ 2,906

Maturities of lease liabilities were as follows:

(Thousands)	Operating
Years Ended December 31,	
2024	$ 1,952
2025	1,323
2026	1,361
2027	1,397
2028	1,428
Thereafter	7,633
Total lease payments	**15,094**
Less: imputed interest	(2,826)
Total	**$ 12,268**

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, 2023 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, 2023 and 2022, SCG reserved $51.3 million and $50.7

million, respectively, related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2023 and 2022, SCG reserved $12.0 million and $12.4 million, respectively, related to the property located on Pine Street in Bridgeport. As of December 31, 2023 and 2022, 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 $357 million and $285 million as of December 31, 2023 and 2022, 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, 2023 and 2022 consisted of:

Description	(Level 1)	(Level 2)	(Level 3)	Total
(Thousands)				
As of December 31, 2023				
Assets				
Non-current investments	$ 10,396	$ —	$ —	$ 10,396
Total	**$ 10,396**	**$ —**	**$ —**	**$ 10,396**
As of December 31, 2022				
Assets				
Non-current investments	$ 9,372	$ —	$ —	$ 9,372
Total	**$ 9,372**	**$ —**	**$ —**	**$ 9,372**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2023 and 2022. 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 $3.1 million for 2023 and $3.3 million for 2022.

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 $4.7 million and $4.8 million at December 31, 2023 and 2022, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 124,074	$ 179,484	$ 15,164	$ 18,423
Service cost	—	857	29	52
Interest cost	6,108	5,522	737	460
Amendments	—	137	—	—
Actuarial loss (gain)	6,834	(32,041)	3,084	(1,749)
Curtailments	—	(2,751)	—	—
Settlements	—	(17,605)	—	—
Benefits paid	(9,923)	(9,529)	(2,293)	(2,022)
Benefit obligation at December 31	**$ 127,093**	**$ 124,074**	**$ 16,721**	**$ 15,164**
Change in plan assets				
Fair value of plan assets at January 1	$ 87,533	$ 142,747	$ 2,939	$ 4,523
Actual return on plan assets	11,010	(29,090)	433	(879)
Employer & plan participants' contributions	3,700	1,010	2,293	1,315
Settlements	—	(17,605)	—	—
Benefits paid	(9,923)	(9,529)	(2,293)	(2,022)
Fair value of plan assets at December 31	**$ 92,320**	**$ 87,533**	**$ 3,372**	**$ 2,937**
Funded status	**$ (34,773)**	**$ (36,541)**	**$ (13,349)**	**$ (12,227)**

During 2023, the pension benefit obligation had an actuarial loss of $6.8 million. This loss was primarily driven by a $5.8 million loss from decrease in discount rates. During 2023, the postretirement benefit obligation had an actuarial loss of $3.1 million. This loss was primarily driven by $0.9 million loss from assumption changes in health care trend rates and $0.6 million loss from decrease in discount rates.

During 2022, the pension benefit obligation had an actuarial gain of $32.0 million. This gain was primarily driven by a $32.0 million gain from increase in discount rates. In 2022, the pension benefit obligation had a reduction of $17.6 million from settlements and $2.8 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the consolidated balance sheet as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Noncurrent liabilities	$ (34,773)	$ (36,541)	$ (13,349)	$ (12,227)

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,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Net actuarial loss (gain)	$ 21,328	$ 21,568	$ 1,524	$ (1,542)
Prior service cost	$ 1,712	$ 1,813	$ 396	$ 824

Our accumulated benefit obligation for all qualified defined benefit pension plans was $127.1 million and $124.1 million as of December 31, 2023 and 2022, respectively. SCG's postretirement benefits were partially funded as of December 31, 2023 and 2022.

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, 2023 and 2022. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2023 and 2022.

As of December 31,	**2023**	**2022**
(Thousands)		
Projected benefit obligation	$ 127,093	$ 124,074
Accumulated benefit obligation	$ 127,093	$ 124,074
Fair value of plan assets	$ 92,320	$ 87,533

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2023 and 2022.

Notes to Consolidated Financial Statements

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Net periodic benefit cost				
Service cost	$ —	$ 857	$ 29	$ 52
Interest cost	6,108	5,522	737	460
Expected return on plan assets	(5,472)	(8,698)	(222)	(308)
Amortization of prior service cost	102	101	427	475
Amortization of actuarial loss (gain)	1,536	1,037	(194)	(143)
Settlements	—	3,005	—	—
Net periodic benefit cost	**$ 2,274**	**$ 1,824**	**$ 777**	**$ 536**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Curtailments	$ —	$ (2,751)	$ —	$ —
Settlements	—	(3,005)	—	—
Current year prior service costs	—	137	—	—
Amortization of prior service cost	(102)	(101)	(427)	(475)
Current year actuarial (gain) loss	1,296	5,747	2,871	(562)
Amortization of actuarial (loss) gain	(1,536)	(1,037)	194	143
Total recognized in regulatory assets and regulatory liabilities	**$ (342)**	**$ (1,010)**	**$ 2,638**	**$ (894)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ 1,932**	**$ 814**	**$ 3,415**	**$ (358)**

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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
Discount rate	4.65 %	5.17 %	4.65 %	5.10 %
Rate of compensation increase	N/A	N/A	N/A	N/A
Interest crediting rate	3.13 %	4.48% / 4.00%	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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2023**	**2022**	**2023**	**2022**
Discount rate	5.17 %	2.85% /4.08% /4.92%	5.10 %	2.61 %
Expected long-term return on plan assets	7.50 %	7.00 %	7.50 %	6.80 %
Rate of compensation increase	N/A	3.50% /3.50% / N/A	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 in excess of 10% of the greater of PBO or MRVA related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the SCG Salaried Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. 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, 2023 and 2022 consisted of:

As of December 31,	2023	2022
Health care cost trend rate (pre 65/post 65)	8.10% / 8.60%	6.00%/6.50%
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	2031/2032	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 $5.6 million to our pension benefits plan in 2024. We expect to contribute $0.1 million to our postretirement benefits plan in 2024.

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
2024	$	12,659	$	1,540	$	91
2025	$	10,817	$	1,482	$	93
2026	$	11,049	$	1,382	$	98
2027	$	10,693	$	1,409	$	7
2028	$	10,815	$	1,343	$	6
2029-2033	$	47,388	$	5,929	$	16

***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 15%-70% for Return-Seeking assets and 30%-85% 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, 2023, by asset category, consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2023				
Cash and cash equivalents	$ 2,198	$ 73	$ 2,125	$ —
U.S. government securities	9,736	9,736	—	—
Common stocks	4,497	4,497	—	—
Registered investment companies	4,683	4,683	—	—
Corporate bonds	24,002	—	24,002	—
Common collective trusts	35,942	—	35,942	—
Other, principally annuity, fixed income	(2,998)	(2)	(2,996)	—
	$ 78,060	**$ 18,987**	**$ 59,073**	**$ —**
Other investments measured at net asset value	14,260			
Total	**$ 92,320**			

The fair values of pension benefits plan assets as of December 31, 2022, by asset category, consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2022				
Cash and cash equivalents	$ 3,167	$ 10	$ 3,157	$ —
U.S. government securities	4,703	4,703	—	—
Common stocks	3,885	3,885	—	—
Registered investment companies	4,363	4,363	—	—
Corporate bonds	22,807	—	22,807	—
Preferred stocks	24	24	—	—
Common collective trusts	31,791	—	31,791	—
Other, principally annuity, fixed income	320	—	320	—
	$ 71,060	**$ 12,985**	**$ 58,075**	**$ —**
Other investments measured at net asset value	16,473			
Total	**$ 87,533**			

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, 2023 consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2023				
Cash and cash equivalents	$ 78	$ 3	$ 75	$ —
U.S. government securities	359	359	—	—
Common stocks	139	139	—	—
Registered investment companies	199	199	—	—
Corporate bonds	868	—	868	—
Common collective trusts	1,408	—	1,408	—
Other, principally annuity, fixed income	(110)	—	(110)	—
	$ 2,941	**$ 700**	**$ 2,241**	**$ —**
Other investments measured at net asset value	431			
Total	**$ 3,372**			

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2022 consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2022				
Cash and cash equivalents	$ 243	$ —	$ 243	$ —
U.S. government securities	145	145	—	—
Common stocks	111	111	—	—
Registered investment companies	179	179	—	—
Corporate bonds	689	—	689	—
Preferred stocks	1	1	—	—
Common collective trusts	1,123	—	1,123	—
Other, principally annuity, fixed income	10	—	10	—
	$ 2,501	**$ 436**	**$ 2,065**	**$ —**
Other investments measured at net asset value	436			
Total	**$ 2,937**			

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, 2023 and 2022.

Note 14. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2023 and 2022, consisted of:

Years Ended December 31,	**2023**	**2022**
(Thousands)		
Interest and dividend income	$ 592	$ 45
Carrying costs on regulatory assets	1,197	1,444
Allowance for funds used during construction	807	1,090
Miscellaneous	43	68
Total other income	**$ 2,639**	**$ 2,647**
Pension non-service components	$ 25	$ (10,243)
Miscellaneous	(2,401)	(1,929)
Total other deductions	**$ (2,376)**	**$ (12,172)**

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 and capital services provided to SCG by AGR and its affiliates was approximately $25.0 million and $17.8 million for the years ended December 31, 2023 and 2022, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $1.0 million for 2023 and $0.8 million for 2022. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by SCG to AGR and its subsidiaries was approximately $5.4 million for 2023 and $5.8 million for 2022. 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 $20.9 million at December 31, 2023 and the balance of $19.7 million at December 31, 2022 is mostly payable to UIL Holdings. The balance in accounts receivable from affiliates of $0.6 million at December 31, 2023 and the balance of $1.6 million at December 31, 2022 is mostly receivable from UI and CNG, respectively.

The balance in notes receivable from affiliates of $15.3 million at December 31, 2023 is receivable from NYSEG and Avangrid. The balance of notes receivable from affiliates of $1.7 million at December 31, 2022 is receivable from 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 March 29, 2024, which is the date these consolidated financial statements were available to be issued.

Central Maine Power Company
and Subsidiaries
Consolidated Financial Statements
As of and for the Years Ended December 31, 2023 and 2022

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 Companyand its subsidiaries (the Company), which comprise the consolidated balance sheets as of December 31, 2023 and 2022, and the related consolidated statements of income, comprehensive income, cash flows, and changes in equity 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, 2023 and 2022, 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 available to be 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 25, 2024

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,	2023	2022
(Thousands)		
Operating Revenues	**$ 1,127,381**	**$ 1,051,204**
Operating Expenses		
Electricity purchased	103,393	50,052
Operations and maintenance	578,500	562,255
Depreciation and amortization	131,383	133,573
Taxes other than income taxes, net	79,134	78,394
Total Operating Expenses	**892,410**	**824,274**
Operating Income	**234,971**	**226,930**
Other income	25,447	15,877
Other deductions	(1,279)	(14,457)
Interest expense, net of capitalization	(66,121)	(47,760)
Income Before Income Tax	**193,018**	**180,590**
Income tax expense	21,126	20,753
Net Income	**171,892**	**159,837**
Less: net income attributable to noncontrolling interest	3,288	3,227
Net Income Attributable to CMP	**$ 168,604**	**$ 156,610**

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,	2023	2022
(Thousands)		
Net Income	**$ 171,892**	**$ 159,837**
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for nonqualified plans and current year actuarial gain, net of income tax	29	224
Unrealized gain during period on derivatives qualifying as cash flow hedges, net of income tax	—	551
Reclassification to net income of gain on cash flow hedges, net of income tax	—	(578)
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax	130	130
Other Comprehensive Income, Net of Tax	**159**	**327**
Comprehensive Income	**172,051**	**160,164**
Less:		
Comprehensive income attributable to noncontrolling interest	3,288	3,227
Comprehensive Income Attributable to CMP	**$ 168,763**	**$ 156,937**

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,		2023		2022
(Thousands)				
Assets				
Current Assets				
Cash and cash equivalents	$	52,570	$	28,463
Accounts receivable and unbilled revenues, net		336,664		290,523
Accounts receivable from affiliates		2,399		6,931
Notes receivable from affiliates		252		240
Materials and supplies		68,495		40,132
Prepayments and other current assets		30,715		27,809
Income tax receivable		3,376		13,302
Regulatory assets		153,887		60,653
Total Current Assets		**648,358**		**468,053**
Utility plant, at original cost		5,466,800		5,226,485
Less accumulated depreciation		(1,588,777)		(1,481,045)
Net Utility Plant in Service		**3,878,023**		**3,745,440**
Construction work in progress		317,707		240,411
Total Utility Plant		**4,195,730**		**3,985,851**
Operating lease right-of-use assets		14,374		15,125
Other property and investments		1,020		959
Regulatory and Other Assets				
Regulatory assets		577,482		404,329
Goodwill		324,938		324,938
Other		157,372		159,613
Total Regulatory and Other Assets		**1,059,792**		**888,880**
Total Assets	**$**	**5,919,274**	**$**	**5,358,868**

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,	2023	2022
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 54,400	$ 46,000
Accounts payable and accrued liabilities	448,582	322,586
Accounts payable to affiliates	41,385	40,892
Interest accrued	18,747	18,393
Taxes accrued	3,399	3,300
Operating lease liabilities	1,117	1,071
Other current liabilities	125,844	110,324
Regulatory liabilities	80,048	86,937
Total Current Liabilities	**773,522**	**629,503**
Regulatory and Other Liabilities		
Regulatory liabilities	307,999	328,080
Other Non-current liabilities		
Deferred income taxes	773,650	691,858
Pension and other postretirement	77,595	59,461
Operating lease liabilities	14,764	15,359
Other	143,435	152,980
Total Regulatory and Other Liabilities	**1,317,443**	**1,247,738**
Non-current debt	1,410,241	1,285,269
Total Liabilities	**3,501,206**	**3,162,510**
Commitments and Contingencies		
Redeemable Preferred Stock	**571**	**571**
CMP Common Stock Equity		
Common stock ($5 par value, 80,000,000 shares authorized and 31,211,471 shares outstanding at December 31, 2023 and 2022)	156,057	156,057
Additional paid-in capital	1,202,132	1,027,439
Retained earnings	1,020,633	977,063
Accumulated other comprehensive loss	(3,057)	(3,216)
Total CMP Common Stock Equity	**2,375,765**	**2,157,343**
Noncontrolling interest	41,732	38,444
Total Equity	**2,417,497**	**2,195,787**
Total Liabilities and Equity	**$ 5,919,274**	**$ 5,358,868**

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,	2023	2022
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 171,892**	**$ 159,837**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	131,383	133,573
Regulatory assets/liabilities amortization	56,415	(8,671)
Regulatory assets/liabilities carrying cost	(1,261)	(886)
Amortization of debt issuance costs	608	588
Deferred taxes	25,119	684
Pension cost	(2,651)	13,673
Stock-based compensation	99	931
Accretion expenses	—	54
Gain on disposal of assets	(458)	(408)
Other non-cash items	(5,170)	(6,188)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(41,609)	13,194
Inventories	(28,363)	(4,406)
Accounts payable, to affiliates, and accrued liabilities	107,753	98,755
Taxes accrued	10,024	(25,300)
Other assets/liabilities	42,141	77,462
Regulatory assets/liabilities	(312,259)	(75,617)
Net Cash Provided by Operating Activities	**153,663**	**377,275**
Cash Flow from Investing Activities:		
Utility plant additions	(366,634)	(297,127)
Contributions in aid of construction	50,134	33,207
Notes receivable from affiliates	(12)	(240)
Proceeds from sale of utility plant	4,319	1,361
Net Cash Used in Investing Activities	**(312,193)**	**(262,799)**
Cash Flow from Financing Activities:		
Non-current note issuance	124,285	123,569
Repayments of non-current debt	—	(125,000)
Payments for finance leases	(14)	39
Notes payable to affiliates	8,400	44,854
Capital contribution	175,000	76,152
Dividends paid	(125,034)	(230,034)
Net Cash Provided by (Used in) Financing Activities	**182,637**	**(110,420)**
Net Increase in Cash and Cash Equivalents	**24,107**	**4,056**
Cash and Cash Equivalents, Beginning of Year	**28,463**	**24,407**
Cash and Cash Equivalents, End of Year	**$ 52,570**	**$ 28,463**

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, 2021	**31,211,471**	**$ 156,057**	**$ 950,478**	**$1,050,487**	**$ (3,543)**	**$ 2,153,479**	**$ 35,217**	**$ 2,188,696**
Net income	—	—	—	156,610	—	156,610	3,227	159,837
Other comprehensive income, net of tax	—	—	—	—	327	327	—	327
Comprehensive income								160,164
Stock-based compensation	—	—	809	—	—	809	—	809
Capital contribution from parent	—	—	76,152	—	—	76,152	—	76,152
Preferred stock dividends	—	—	—	(34)	—	(34)	—	(34)
Common stock dividends	—	—	—	(230,000)	—	(230,000)	—	(230,000)
Balances, December 31, 2022	**31,211,471**	**156,057**	**1,027,439**	**977,063**	**(3,216)**	**2,157,343**	**38,444**	**2,195,787**
Net income	—	—	—	168,604	—	168,604	3,288	171,892
Other comprehensive income, net of tax	—	—	—	—	159	159	—	159
Comprehensive income								172,051
Stock-based compensation	—	—	(307)	—	—	(307)	—	(307)
Capital contribution from parent	—	—	175,000	—	—	175,000	—	175,000
Preferred stock dividends	—	—	—	(34)	—	(34)	—	(34)
Common stock dividends	—	—	—	(125,000)	—	(125,000)	—	(125,000)
Balances, December 31, 2023	**31,211,471**	**$ 156,057**	**$ 1,202,132**	**$1,020,633**	**$ (3,057)**	**$ 2,375,765**	**$ 41,732**	**$ 2,417,497**

(*) 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 665,900 customers as of December 31, 2023, 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 Versant Power (Versant). Versant is wholly-owned by ENMAX Corp. 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 81.6% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

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 primarily 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 2.3% and 2.5% of average depreciable property for 2023 and 2022, respectively. We amortize our capitalized software cost, which is included in other plant, using the straight line method, based on useful lives of 5-15 years. Capitalized software costs were approximately $197.3 million as of December 31, 2023, and $181.2 million as of December 31, 2022. Depreciation expense was $122.1 million in 2023 and $124.1 million in 2022. Amortization of capitalized software was $9.3 million and $9.5 million in 2023 and 2022, respectively.

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)**	**2023**	**2022**
(Thousands)			
Electric			
Transmission	4-70	$ 2,864,360	$ 2,814,733
Distribution	5-75	1,971,837	1,813,459
Vehicles	4-10	79,545	70,987
Other	4-50	551,058	527,306
Total Utility Plant in Service		**5,466,800**	**5,226,485**
Total accumulated depreciation		(1,588,777)	(1,481,045)
Total Net Utility Plant in Service		**3,878,023**	**3,745,440**
Construction work in progress		317,707	240,411
Total Utility Plant		**$ 4,195,730**	**$ 3,985,851**

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. If the amounts in OCI are probable of recovery in the ratemaking process, then the OCI is reclassified as a regulatory asset or liability. 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.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

(Thousands)	2023	2022
Cash paid (refunded) during the year ended December 31:		
Interest, net of amounts capitalized	$ 47,418	$ 46,729
Income taxes (refunded) paid, net	$ (13,920)	$ 45,224

Of the income taxes (refunded) paid, substantially all was (refunded by) paid to AGR under the tax sharing agreement. Interest capitalized was $5.9 million in 2023 and $3.6 million in 2022. Accrued liabilities for utility plant additions were $53.2 million and $35.2 million as of December 31, 2023 and 2022, respectively.

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 $45.3 million for 2023 and $41.0 million for 2022, and are shown net of an allowance for credit losses at December 31 of $14.7 million for 2023 and $16.9 million for 2022. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $5.1 million in 2023 and $6.1 million in 2022.

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. We 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 $7.0 million for 2023 and $9.7 million for 2022. DPA receivable balances at December 31 were $24.0 million for 2023 and $28.0 million for 2022.

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.

The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2023 and 2022 consisted of:

(Thousands)	Government grants	Total
As of December 31, 2021	**$ 34,030**	**$ 34,030**
Disposals	—	—
Recognized in income	(3,578)	(3,578)
As of December 31, 2022	**30,452**	**30,452**
Disposals	—	—
Recognized in income	(3,789)	(3,789)
As of December 31, 2023	**$ 26,663**	**$ 26,663**

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the government. We believe we are in compliance with each grant's terms and conditions as of December 31, 2023 and 2022.

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 of asbestos in buildings. 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, 2023 and 2022.

Years Ended December 31,		**2023**		**2022**
(Thousands)				
ARO, beginning of year	$	972	$	1,027
Liabilities settled during the year		—		(109)
Accretion expenses		—		54
ARO, end of year	**$**	**972**	**$**	**972**

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 2057.

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. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 in excess of 10% of the greater of periodic benefit obligation or market-related value of assets over average remaining service. 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: In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax (“CAMT”) of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The CAMT and other various applicable provisions of the IRA are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year, as well as on anticipated guidance from the U.S. Department of Treasury.

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 receivable balance due from AGR at December 31, 2023 was $3.4 million. The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2022 was $13.3 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 regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit 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, 2023 and 2022.

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. We consider the effect of the alternative minimum tax system in determining the need for a valuation allowance for deferred taxes. 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. There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2023 that are expected to have a material impact on CMP’s consolidated financial statements.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(a) Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance to enhance income tax disclosures. The two primary enhancements relate to disaggregation of the annual disclosures for the effective tax rate reconciliation and income taxes paid. For the rate reconciliation, it requires additional disaggregation of information in a tabular format using both percentages and amounts broken out into specific categories (e.g., state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, and changes in unrecognized tax benefits). For income taxes paid, it requires disaggregation by jurisdiction (e.g., federal, state and foreign). We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

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.

Union collective bargaining agreements: Approximately 64% 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 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 and full reconciliation of exceptional costs as identified in CMP's rate plan.

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 Other FERC Matters

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 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 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.

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 $30.1 million as of December 31, 2023, which has not changed since December 31, 2022, 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 $12.8 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, the 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, or RPM, 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. 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. On August 9, 2022, the D.C. Circuit Court vacated FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the RPM after initially, and forcefully, rejecting it and that because the FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. We cannot predict the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the NETO's 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 three 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

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17.4 million, or approximately 6.9%, based on an allowed ROE of 9.25% and a 50.00% equity ratio. The rate increase was effective March 1, 2020. Commencing on March 1, 2020, the MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP’s customer service performance following the implementation of its new billing system in 2017 which would be removed after demonstrating satisfactory customer service performance. In September 2021, CMP met the 18-month required rolling average satisfactory customer service benchmarks and filed with the MPUC a request for removal of the management efficiency adjustment, which was approved by the MPUC effective as of its February 18, 2022 order.

On February 18, 2022, the MPUC opened a narrowly tailored follow-on investigation examining how CMP and its customers are affected by decisions made at the CMP corporate parent level about earnings, capital budgeting, and planning. In this context, the investigation will also examine regulatory approaches and structures including ratemaking and performance mechanisms. In an order dated February 7, 2023, the MPUC closed this investigation after consolidating its records with CMP's pending rate case.

In accordance with Chapter 120 of MPUC Rules, on May 26, 2022, CMP filed a nonbinding notice of intent to file a distribution rate case on or after sixty days from the issuance of the letter. In the notice, CMP signaled its intent to propose a three-year rate plan, which includes a multi-year capital investment plan to fund investments needed to improve reliability and resiliency, as well as to continue to improve the customer experience and cost-effectively advance clean energy transformation. CMP’s notice estimated a revenue change in the range of $45 to $50 million in the first year of the rate plan followed by increases in the range of $25 to $30 million in the second year and $20 to $25 million in the third year.

On August 11, 2022, CMP filed a three year rate plan, with adjustments to the distribution revenue requirement in each year. Following discovery and technical conferences and settlement negotiations, on May 31, 2023, CMP filed a Stipulation resolving all issues in the case providing for a 9.35% ROE, 50% equity ratio, and 50% earnings sharing for annual earnings in excess of 100 basis points of CMP’s allowed ROE. The Stipulation also provides for a two year forward looking rate plan with increases to occur in four equal levelized amounts every six months beginning on July 1, 2023. The next three increases will occur on January 1, 2024, July 1, 2024, and January 1, 2025. The amount of each increase is $16.75 million. These revenue increases include amounts for operations and maintenance but are primarily driven by increases in capital investment forecast by CMP to occur during the period covered by the Stipulation. The Stipulation also implements a service quality indicator incentive mechanism. The incentive is provided by a negative revenue adjustment mechanism that would impose a maximum of $8.8 million per year for a failure to meet specified service quality indicator targets. No party opposed the Stipulation and it was approved in its entirety by the MPUC on June 6, 2023.

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 $9 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 $2.5 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. On September 11, 2020 the project was assigned to New England Aqua Ventus, LLC. 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, eight contracts have been terminated prior to achieving Commercial Operations. In October 2021 CMP executed contracts with 6 additional facilities (Tranche 2), 1 contract terminated in 2023 prior to achieving Commercial Operations. 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 term sheet proposals for long-term contracts 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 $256.9 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.

Regulatory assets at December 31, 2023 and 2022 consisted of:

As of December 31,	2023	2022
(Thousands)		
Asset retirement obligation	$ 965	$ 965
Deferred meter replacement costs	19,059	21,043
Energy efficiency programs	281	—
Environmental remediation costs	361	318
Federal tax depreciation normalization adjustment	12,651	13,087
Non-bypassable charges (stranded costs)	88,476	14,497
Pension and other post retirement benefits	100,545	79,154
Pension and other post retirement benefits cost deferrals	11,606	11,753
Storm costs	260,721	121,388
Transmission revenue reconciliation mechanism	250	10,890
Unamortized losses on reacquired debt	90	166
Unfunded future income taxes	227,570	189,008
Other	8,794	2,713
Total regulatory assets	**731,369**	**464,982**
Less: current portion	153,887	60,653
Total non-current regulatory assets	**$ 577,482**	**$ 404,329**

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.

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 our 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.

Non-bypassable charges (stranded costs) 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.

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 represent the distribution related portion of lump-sum pension settlement expense to be amortized in future rates.

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 $260.7 million at December 31, 2023 and $121.4 million at December 31, 2022.

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. The ATU (Annual Transmission True Up) portion is recovered over the subsequent January to December 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).

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 CRM&B (Billing System Costs), OPA Assessment for Non-Wire Alternatives, 100 BP Recovery, Rate Case Expenses, Electric Lifeline Program (ELP), Revenue Levelization and Arrears Forgiveness.

Regulatory liabilities at December 31, 2023 and 2022 consisted of:

As of December 31,	**2023**	**2022**
(Thousands)		
Accrued removal obligations	$ 25,965	$ 32,434
Environmental remediation costs	1,350	1,228
Rate refund - FERC ROE proceeding	30,114	27,852
Revenue decoupling mechanism	7,474	13,314
Tax Act - remeasurement	263,608	274,691
Transmission revenue reconciliation mechanism	56,575	63,775
Other	2,961	1,723
Total regulatory liabilities	**388,047**	**415,017**
Less: current portion	80,048	86,937
Total non-current regulatory liabilities	**$ 307,999**	**$ 328,080**

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.

Rate refund - FERC ROE proceedings: 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.

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. The ATU is recovered over the subsequent January to December 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 ELP, Vegetation Management and Tax Basis Repairs.

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 years ended December 31, 2023 and 2022 are as follows:

Years Ended December 31,	**2023**	**2022**
(Thousands)		
Regulated operations – electricity	$ 1,050,617	$ 975,064
Other (a)	25,221	42,832
Revenue from contracts with customers	**1,075,838**	**1,017,896**
Leasing revenue	1,551	1,574
Alternative revenue programs	26,822	4,516
Other revenue	23,170	27,218
Total operating revenues	**$ 1,127,381**	**$ 1,051,204**

(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 2023 and 2022 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2023 or 2022 that required us to update the assessment.

The carrying amount of goodwill was $324.9 million at both December 31, 2023 and 2022, with no accumulated impairment losses and no changes during 2023 and 2022.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Current				
Federal	$	(4,502)	$	15,256
State		509		4,813
Current taxes charged to (benefit) expense		**(3,993)**		**20,069**
Deferred				
Federal		16,197		(7,797)
State		8,922		8,481
Deferred taxes charged to expense		**25,119**		**684**
Total Income Tax Expense	**$**	**21,126**	**$**	**20,753**

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, 2023 and 2022 consisted of:

Years Ended December 31,		**2023**		**2023**
(Thousands)				
Tax expense at federal statutory rate	$	40,534	$	37,924
Property related flow through		(19,313)		(8,743)
State tax expense, net of federal benefit		7,450		10,502
Excess ADIT giveback		(7,973)		(19,302)
Other, net		428		372
Total Income Tax Expense	**$**	**21,126**	**$**	**20,753**

Income tax expense for the year ended December 31, 2023 was $19.4 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess Accumulated Deferred Income Tax (ADIT) amortization, property related flow through, partially offset by state taxes. This resulted in an effective tax rate of 10.9%. Income tax expense for the year ended December 31, 2022 was $17.2 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 11.5%.

Deferred tax assets and liabilities as of December 31, 2023 and 2022 consisted of:

December 31,		2023		2022
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	756,028	$	701,941
Unfunded future income taxes		51,831		48,331
Pension and other postretirement benefits		14,151		13,149
Regulatory liability due to "Tax Cuts and Jobs Act"		(73,955)		(77,064)
Federal and state NOL's		(42,880)		(2,971)
Storm costs		73,145		—
Other		(4,670)		8,472
Total Non-current Deferred Income Tax Liabilities	**$**	**773,650**	**$**	**691,858**
Deferred tax assets	$	121,505	$	80,035
Deferred tax liabilities		895,155		771,893
Net Accumulated Deferred Income Tax Liabilities	**$**	**773,650**	**$**	**691,858**

CMP has gross Maine state net operating losses of $293.3 million for the year ended December 31, 2023. CMP had gross Maine state net operating losses of $52.1 million for the year ended December 31, 2022.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2023, 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, 2023 and 2022 consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Beginning Balance	$	12,241	$	15,785
Reduction for tax positions related to prior years		(3,252)		(3,544)
Ending Balance	**$**	**8,989**	**$**	**12,241**

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, 2023 or 2022.

Note 7. Non-current Debt

Long-term debt as of December 31, 2023 and 2022 consisted of:

As of December 31,		2023		2022	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2025-2052	$ 1,275,000	1.87%-6.04%	$ 1,150,000	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		(4,759)		(4,731)	
Total Debt		**1,410,241**		**1,285,269**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 1,410,241**		**$ 1,285,269**	

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

On December 13, 2023, CMP issued $55 million aggregate principal amount of Green First Mortgage Bonds maturing in 2029 at an interest rate of 5.65% and $70 million aggregate principal amount of Green First Mortgage Bonds maturing in 2038 at an interest rate of 6.04%.

On December 15, 2022, CMP issued $75 million aggregate principal amount of Green First Mortgage Bonds maturing in 2032 at an interest rate of 4.37% and $50 million aggregate principal amount of Green First Mortgage Bonds maturing in 2052 at an interest rate of 4.76%.

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

2024	2025	2026	2027	2028	Total
(Thousands)					
$ —	$ 80,000	$ 80,000	$ —	$ 60,000	$ 220,000

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2023 and 2022.

Note 8. Bank Loans and Other Borrowings

CMP had $54.4 million of notes payable at December 31, 2023 and $46.0 million at December 31, 2022. 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, 2023 and $7.0 million outstanding at December 31, 2022.

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 $54.4 million outstanding under this agreement at December 31, 2023 and $39.0 million outstanding at December 31, 2022.

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, 2023 and 2022.

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 0.38 to 1.00 at December 31, 2023. We are not in default as of December 31, 2023.

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, 2023 and 2022, our redeemable preferred stock was:

				Amount (Thousands)	
Series	**Par Value per Share**	**Redemption Price per Share**	**Shares Authorized and Outstanding(a)**	**2023**	**2022**
CMP, 6% Non-callable	$ 100	$ —	5,713	$ 571	$ 571
Total				**$ 571**	**$ 571**

[a] At December 31, 2023 and 2022, 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 35 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,		2023		2022
(Thousands)				
Lease cost				
Finance lease cost				
Amortization of right-of-use assets	$	293	$	285
Interest on lease liabilities		1		(38)
Total finance lease cost		294		247
Operating lease cost		1,577		1,463
Short-term lease cost		76		50
Variable lease cost		39		37
Total lease cost	**$**	**1,986**	**$**	**1,797**

Balance sheet and other information for the years ended December 31, 2023 and 2022 was as follows:

As of December 31,		2023		2022
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right-of-use assets	$	14,374	$	15,125
Operating lease liabilities, current		1,117		1,071
Operating lease liabilities, long-term		14,764		15,359
Total operating lease liabilities	$	15,881	$	16,430
Finance Leases				
Other assets	$	3,471	$	3,764
Other current liabilities		13		13
Other non-current liabilities		3		17
Total finance lease liabilities	$	16	$	30
Weighted-average Remaining Lease Term (years)				
Finance leases		1.33		2.33
Operating leases		16.41		16.26
Weighted-average Discount Rate				
Finance leases		3.47 %		3.47 %
Operating leases		3.97 %		3.89 %

For the years ended December 31, 2023 and 2022, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,	2023	2022
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,493	$ 1,547
Operating cash flows from finance leases	$ 1	$ (38)
Financing cash flows from finance leases	$ 14	$ (39)
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$ —	$ (9)
Operating leases	$ 505	$ 1,332

As of December 31, 2023, maturities of lease liabilities were as follows:

	Finance Leases	Operating Leases
(Thousands)		
Year ending December 31,		
2024	$ 13	$ 1,542
2025	3	1,428
2026	—	1,512
2027	—	1,076
2028	—	1,091
Thereafter	—	16,019
Total lease payments	**16**	**22,668**
Less: imputed interest	—	(6,787)
Total	**$ 16**	**$ 15,881**

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 $104.0 million for non-utility generator power in 2023 and $20.3 million in 2022 recorded for non-utility generator power in the consolidated statements of income.

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 Environmental Protection Agency (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 five waste sites. The five sites do not include sites where coal gas was manufactured in the past, which are discussed below. With respect to the five sites, four sites are included in Maine's Uncontrolled Sites Program (MUSP), one is subject to Maine's Waste Management Program and one is included on the Massachusetts Non-Priority Confirmed Disposal Site list. Two of the 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 $1.5 million related to the five sites at December 31, 2023.

We have recorded an estimated liability of $3.5 million at December 31, 2023, related to three additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs as a result of being 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 nine total sites ranges from $4.3 million to $10.9 million as of December 31, 2023. 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 and/or monitoring at our three sites where coal gas was manufactured in the past. The three sites are in Maine's Voluntary Response Action Program, Brownfield Cleanup Program or MUSP.

Our estimate for costs related to investigation, remediation and/or monitoring of the sites ranges from $0.1 million to $0.2 million at December 31, 2023. 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, changes due to property use and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive coal gas manufacturing sites was $0.1 million and $0.2 million at December 31, 2023 and 2022, respectively. We recorded a corresponding regulatory asset 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 2057.

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.

We did not have any derivatives designated as hedging instruments as of December 31, 2023 and December 31, 2022.

The effect of hedging instruments on OCI and income for the years ended December 31, 2023 and 2022, respectively, consisted of:

Years Ended December 31,	Gain 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)				
2023				
Interest rate contracts	$ —	Interest expense	$ (181)	$ 66,121
Commodity contracts: Other	—	Other operating expenses	—	$ 578,500
Total	**$ —**		**$ (181)**	
2022				
Interest rate contracts	$ —	Interest expense	$ (181)	$ 47,760
Commodity contracts: Other	765	Other operating expenses	803	$ 562,255
Total	**$ 765**		**$ 622**	

The amount in AOCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $1.9 million for 2023 and $2.1 million for 2022. For the year ended December 31, 2023, 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 2024.

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

The estimated fair value of debt amounted to $1,348 million and $1,182 million as of December 31, 2023 and 2022, 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

There were no financial instruments measured at fair value on recurring basis as of December 31, 2023 and December 31, 2022, as a result of the termination of the fleet fuel program effective September 30, 2022. We had no transfers to or from Level 1 and 2 during the year ended December 31, 2022. 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 may 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, 2023 and 2022 consisted of:

Years Ended December 31,	2023	2022
(Thousands)		
Beginning balance	$ —	$ 38
Total (losses) gains (realized/unrealized)		
Included in earnings	—	(803)
Included in other comprehensive income	—	765
Ending balance	**$ —**	**$ —**

The amounts of realized and unrealized gain and loss included in earnings for the periods 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, 2023 and 2022 consisted of:

	Balance December 31, 2021	2022 Change	Balance December 31, 2022	2023 Change	Balance December 31, 2023
(Thousands)					
Amortization of pension cost for nonqualified plans and current year actuarial gain, net of income tax expense of $87 for 2022 and $11 for 2023	$ (1,896)	$ 224	$ (1,672)	$ 29	$ (1,643)
Unrealized gain on derivatives qualified as hedges:					
Unrealized gain during period on derivatives qualified as hedges, net of income tax expense of $214 for 2022 and $0 for 2023		551		—	
Reclassification adjustment for gain included in net income, net of income tax benefit of ($225) for 2022 and $0 for 2023		(578)		—	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $51 for both 2022 and 2023		130		130	
Net unrealized gain on derivatives qualified as hedges	(1,647)	103	(1,544)	130	(1,414)
Accumulated Other Comprehensive Loss	**$ (3,543)**	**$ 327**	**$ (3,216)**	**$ 159**	**$ (3,057)**

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. During 2022, the Company decided to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to the 401(k) Plan. 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 $9.3 million for 2023 and $7.9 million for 2022.

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 $1.2 million at both December 31, 2023 and 2022.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 273,954**	**$ 407,423**	**$ 60,789**	**$ 94,024**
Service cost	1,705	4,673	298	537
Interest cost	13,686	12,447	2,980	2,491
Curtailments/Settlements	—	(50,326)	—	—
Actuarial loss (gain)	15,366	(83,071)	10,765	(28,899)
Benefits paid	(17,760)	(17,192)	(6,744)	(7,364)
Benefit obligation as of December 31,	**$ 286,951**	**$ 273,954**	**$ 68,088**	**$ 60,789**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 260,536**	**$ 368,366**	**$ 14,746**	**$ 22,161**
Actual return on plan assets	21,636	(76,432)	2,155	(4,036)
Employer contributions	—	20,000	2,875	3,985
Settlements	—	(34,206)	—	—
Benefits paid	(17,760)	(17,192)	(6,744)	(7,364)
Fair value of plan assets at December 31,	**$ 264,412**	**$ 260,536**	**$ 13,032**	**$ 14,746**
Funded status at December 31,	**$ (22,539)**	**$ (13,418)**	**$ (55,056)**	**$ (46,043)**

During 2023, the pension obligation had an actuarial loss of $15.4 million. This loss was primarily driven by $14.4 million loss from decrease in discount rates. During 2023, the postretirement benefit obligation had an actuarial loss of $10.8 million. This loss was primarily driven by $6.8 million loss from assumption changes in health care trend rates and $2.9 million loss from decrease in discount rates.

During 2022, the pension and postretirement benefit obligations had actuarial gains of, respectively, $83.1 million and $28.9 million, primarily due to gains from discount rate increases of $81.7 million and $15.6 million, respectively. The pension benefit obligation had a reduction of $50.3 million from settlements ($34.2 million) and curtailments ($16.1 million). The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan.

Amounts recognized in the consolidated balance sheets as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Non-current liabilities	$ (22,539)	$ (13,418)	$ (55,056)	$ (46,043)

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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Net loss (gain)	$ 93,715	$ 81,944	$ 6,830	$ (2,789)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $280.2 million and $267.2 million as of December 31, 2023 and 2022. Our postretirement benefits were partially funded at December 31, 2023 and 2022.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2023 and 2022. 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,	**2023**	**2022**
(Thousands)		
Projected benefit obligation	$ 286,951	$ 273,954
Accumulated benefit obligation	$ 280,184	$ 267,157
Fair value of plan assets	$ 264,412	$ 260,536

As of December 31, 2023 and 2022, 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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
For the years ended December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 1,705	$ 4,673	$ 298	$ 537
Interest cost	13,686	12,447	2,980	2,491
Expected return on plan assets	(18,042)	(19,483)	(1,009)	(1,323)
Amortization of prior service benefit	—	—	—	(637)
Settlement charge	—	10,096	—	—
Amortization of net loss	—	5,940	—	1,321
Net Periodic Benefit Cost	**$ (2,651)**	**$ 13,673**	**$ 2,269**	**$ 2,389**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net loss (gain)	$ 11,772	$ 12,844	$ 9,619	$ (23,539)
Amortization of net loss	—	(5,940)	—	(1,321)
Settlements	—	(10,096)	—	—
Curtailments	—	(16,120)	—	—
Amortization of prior service benefit	—	—	—	637
Total Other Changes	**11,772**	**(19,312)**	**$ 9,619**	**(24,223)**
Total Recognized	**$ 9,121**	**$ (5,639)**	**$ 11,888**	**$ (21,834)**

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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
	2023	2022	2023	2022
Discount rate	4.75%	5.21% / 5.25% Union	4.65%	5.13%
Rate of compensation increase	3.00% for Union	3.00%	3.00% for Union	3.00% for Union
Interest crediting rate	3.52%	4.48% 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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	2023	2022	2023	2022
Discount rate	5.21 %	2.96% / 4.15% / 3.05%	5.13 %	2.74 %
Expected long-term return on plan assets	6.00 %	6.50% / 5.00% / 6.00%	6.84 %	5.97 %
Rate of compensation increase (Union/ Non-Union)	3.00% for Union	Age-Related Rates / 3.50% Union	3.00% for Union	3.50% for Union

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, 2023 and 2022 consisted of:

As of December 31,	2023	2022
Health care cost trend rate assumed for next year	8.10% / 8.60%	6.00% / 6.50%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50% / 4.50%	4.50 %
Year that the rate reaches the ultimate trend rate	2031 / 2032	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 do not expect to contribute to our pension or other postretirement plans during 2024.

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, 2023 consisted of:

(Thousands)		Pension Benefits		Postretirement Benefits		Medicare Act Subsidy Receipts
2024	$	25,765	$	5,603	$	169
2025	$	24,816	$	5,426	$	184
2026	$	24,464	$	5,321	$	195
2027	$	24,354	$	5,244	$	206
2028	$	23,581	$	5,098	$	223
2029 - 2033	$	108,947	$	24,431	$	652

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 15%-70% for Return-Seeking assets and 30%-85% for Liability-Hedging assets. Return-Seeking assets include investments in domestic, international and emerging equity, 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, 2023, consisted of:

As of December 31, 2023		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 10,580	$ (229)	$ 10,809	$ —
U.S. government securities	35,025	35,025	—	—
Common stocks	9,874	9,874	—	—
Registered investment companies	13,261	13,261	—	—
Corporate bonds	82,140	—	82,140	—
Common collective trusts	62,215	—	62,215	—
Other, principally annuity, fixed income	(453)	—	(453)	—
	$ 212,642	**$ 57,931**	**$ 154,711**	**$ —**
Other investments measured at net asset value	51,770			
Total	**$ 264,412**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 7,298	$ 18	$ 7,280	$ —
U.S. government securities	22,837	22,837	—	—
Common stocks	7,819	7,819	—	—
Registered investment companies	12,796	12,796	—	—
Corporate bonds	79,902	—	79,902	—
Preferred stocks	92	92	—	—
Common collective trusts	67,859	—	67,859	—
Other, principally annuity, fixed income	473	—	473	—
	$ 199,076	**$ 43,562**	**$ 155,514**	**$ —**
Other investments measured at net asset value	61,460			
Total	**$ 260,536**			

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 of increasing the projected expected return, while mitigating 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, 2023, consisted of:

As of December 31, 2023		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 727	$ 4	$ 723	$ —
U.S. government securities	567	567	—	—
Common stocks	314	314	—	—
Registered investment companies	7,118	7,118	—	—
Corporate bonds	1,379	—	1,379	—
Common collective trusts	2,311	—	2,311	—
Other, principally annuity, fixed income	(175)	—	(175)	—
	$ 12,241	**$ 8,003**	**$ 4,238**	**$ —**
Other investments measured at net asset value	791			
Total	**$ 13,032**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 602	$ 1	$ 601	$ —
U.S. government securities	259	259	—	—
Common stocks	277	277	—	—
Registered investment companies	9,656	9,656	—	—
Corporate bonds	1,188	—	1,188	—
Preferred stocks	1	1	—	—
Common collective trusts	1,938	—	1,938	—
Other, principally annuity, fixed income	18	—	18	—
	$ 13,939	**$ 10,194**	**$ 3,745**	**$ —**
Other investments measured at net asset value	807			
Total	**$ 14,746**			

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, 2023 and 2022.

Note 17. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Allowance for funds used during construction	$	10,983	$	12,585
Carrying costs on regulatory assets		12,268		2,881
Equity earnings		61		58
Miscellaneous		2,135		353
Total other income	**$**	**25,447**	**$**	**15,877**
Pension non-service components	$	2,166	$	(10,899)
Miscellaneous		(3,445)		(3,558)
Total other deductions	**$**	**(1,279)**	**$**	**(14,457)**

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 $50.4 million and $44.9 million for 2023 and 2022, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $8.5 million in 2023 and $9.5 million in 2022. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by CMP to AGR and its subsidiaries were approximately $7.0 million for 2023 and $9.4 million for 2022. 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 $41.4 million at December 31, 2023 and the balance of $40.9 million at December 31, 2022 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $2.4 million at December 31, 2023 and the balance of $6.9 million at December 31, 2022 is mostly receivable from NECEC.

Notes receivable from affiliates at December 31, 2023 and at December 31, 2022 of $0.3 million and $0.2 million, respectively, are from Avangrid, Inc. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

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.

On January 4, 2021, in connection with certain stipulation agreements (Stipulations), CMP transferred the NECEC project 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. 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 that CMP is improving related to the NECEC interconnection. The accrued amount was paid to CMP in January 2022.

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. 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. In July 2023 the Stipulations payments resumed when NECEC Transmission LLC restarted construction on the project. For the year ended December 31, 2023, CMP has received $2.3 million in payments from NECEC Transmission LLC.

Note 19. Subsequent Events

The company has performed a review of subsequent events through March 25, 2024, which is the date these consolidated financial statements were available to be issued.

The Berkshire Gas Company
Financial Statements
As of and for the Years Ended December 31, 2023 and 2022

The Berkshire Gas Company

Index

Page

Financial Statements As of and for the Years Ended December 31, 2023 and 2022

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

Independent Auditors' Report

The Stockholder and 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, 2023 and 2022, 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, 2023 and 2022, 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 available to be 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.

KPMG

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 29, 2024

The Berkshire Gas Company
Statements of Income

Years Ended December 31,		2023		2022
(Thousands)				
Operating Revenues	$	**96,584**	$	**101,757**
Operating Expenses				
Natural gas purchased		27,025		42,103
Operations and maintenance		38,206		33,467
Depreciation and amortization		9,313		9,088
Taxes other than income taxes, net		7,581		7,581
Total Operating Expenses		**82,125**		**92,239**
Operating Income		**14,459**		**9,518**
Other income		1,064		859
Other deductions		(333)		(972)
Interest expense, net of capitalization		(3,071)		(2,742)
Income Before Tax		**12,119**		**6,663**
Income tax expense		3,203		562
Net Income	$	**8,916**	$	**6,101**

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

The Berkshire Gas Company
Statements of Comprehensive Income

Years Ended December 31,		2023		2022
(Thousands)				
Net Income	$	**8,916**	$	**6,101**
Other Comprehensive Income (Loss), Net of Tax				
Remeasurement of non-qualified plan, net of income tax benefit of ($21) for 2023 and income tax expense of $21 for 2022		(57)		57
Other Comprehensive Income (Loss), Net of Tax		**(57)**		**57**
Comprehensive Income	$	**8,859**	$	**6,158**

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

The Berkshire Gas Company
Balance Sheets

As of December 31,	2023	2022
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 488	$ 668
Accounts receivable and unbilled revenues, net	16,812	19,705
Accounts receivable from affiliates	5	4
Fuel and gas in storage	3,538	4,436
Materials and supplies	3,344	2,249
Income tax receivable	—	2,478
Other current assets	684	366
Regulatory assets	14,396	14,653
Total Current Assets	**39,267**	**44,559**
Utility plant, at original cost	349,882	321,780
Less accumulated depreciation	(107,271)	(106,642)
Net Utility Plant in Service	**242,611**	**215,138**
Construction work in progress	3,144	7,242
Total Utility Plant	**245,755**	**222,380**
Operating lease right-of-use assets	100	105
Other property and investments	2,170	1,990
Regulatory and Other Assets		
Regulatory assets	18,728	20,115
Goodwill	51,932	51,932
Other	16	10
Total Regulatory and Other Assets	**70,676**	**72,057**
Total Assets	**$ 357,968**	**$ 341,091**

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

The Berkshire Gas Company
Balance Sheets

As of December 31,	2023	2022
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 17,200	$ 9,650
Accounts payable and accrued liabilities	14,934	24,237
Accounts payable to affiliates	5,371	1,048
Interest accrued	818	758
Taxes accrued	1,692	100
Operating lease liabilities	7	7
Regulatory liabilities	463	—
Other	4,159	3,307
Total Current Liabilities	**44,644**	**39,107**
Regulatory and Other Liabilities		
Regulatory liabilities	51,866	51,824
Other Non-current Liabilities		
Deferred income taxes	32,790	30,383
Pension and other postretirement	12,779	12,537
Operating lease liabilities	92	96
Environmental remediation costs	1,978	2,342
Other	1,333	1,220
Total Regulatory and Other Liabilities	**100,838**	**98,402**
Non-current debt	59,642	59,595
Total Liabilities	**205,124**	**197,104**
Commitments and Contingencies		
Common Stock Equity		
Additional paid-in capital	126,504	126,506
Retained earnings	26,340	17,424
Accumulated other comprehensive income	—	57
Total Common Stock Equity	**152,844**	**143,987**
Total Liabilities and Equity	**$ 357,968**	**$ 341,091**

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

The Berkshire Gas Company
Statements of Cash Flows

Years Ended December 31,	2023	2022
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 8,916**	**$ 6,101**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	9,313	9,088
Regulatory assets/liabilities amortization	242	(533)
Regulatory assets/liabilities carrying cost	(858)	(765)
Amortization of debt issuance costs	47	26
Deferred taxes	2,127	3,115
Pension cost	792	252
Stock-based compensation	51	90
Gain on disposal of assets	(76)	—
Other non-cash items	(124)	244
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	2,892	(3,959)
Inventories	(197)	(2,250)
Accounts payable, to affiliates, and accrued liabilities	(9,539)	3,572
Taxes accrued	4,069	(9,695)
Other assets/liabilities	(46)	(5,070)
Regulatory assets/liabilities	673	3,553
Net Cash Provided by Operating Activities	**18,282**	**3,769**
Cash Flow From Investing Activities:		
Capital expenditures	(26,779)	(17,629)
Contributions in aid of construction	567	303
Proceeds from sale of property, plant and equipment	200	38
Net Cash Used in Investing Activities	**(26,012)**	**(17,288)**
Cash Flow From Financing Activities:		
Notes payable to affiliates	7,550	9,650
Capital contributions	—	10,000
Dividends paid	—	(10,000)
Net Cash Provided by (Used in) Financing Activities	**7,550**	**9,650**
Net (Decrease) Increase in Cash and Cash Equivalents	**(180)**	**(3,869)**
Cash and Cash Equivalents, Beginning of Period	**668**	**4,537**
Cash and Cash Equivalents, End of Period	**$ 488**	**$ 668**

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	Accumulated Other Comprehensive Income	Total Common Stock Equity
Balance, December 31, 2021	100	$ —	$ **116,443**	$ **21,323**	$ —	$ **137,766**
Net income	—	—	—	6,101	—	6,101
Other comprehensive income, net of tax	—	—	—	—	57	57
Comprehensive income						6,158
Stock-based compensation	—	—	63	—	—	63
Common stock dividends				(10,000)		(10,000)
Capital contributions	—	—	10,000	—	—	10,000
Balance at December 31, 2022	**100**	**—**	**126,506**	**17,424**	**57**	**143,987**
Net income	—	—	—	8,916		8,916
Other comprehensive loss, net of tax	—	—	—	—	(57)	(57)
Comprehensive income						8,859
Stock-based compensation	—	—	(2)	—	—	(2)
Balance at December 31, 2023	**100**	**$ —**	**$ 126,504**	**$ 26,340**	**$ —**	**$ 152,844**

(*) Par value of share amounts is $2.50

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*:** 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, 2023. 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 81.6% 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) and are also maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the DPU.

***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 primarily 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 2.4% of average depreciable property for 2023 and 2.7% of average depreciable property for 2022. We amortize our capitalized software cost, using the straight-line method, based on useful lives of 6 to 12 years. Depreciation expense was $8.2 million in both 2023 and 2022. Amortization of capitalized software was $1.1 million in 2023 and $0.9 million in 2022.

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)		2023		2022
(Thousands)					
Gas distribution plant	4-68	$	284,440	$	266,562
Software	6-12		13,152		12,704
Land			2,305		2,305
Buildings and improvements	50-55		33,358		32,228
Other plant	25-55		16,627		7,981
Utility plant at original cost			**349,882**		**321,780**
Less accumulated depreciation			(107,271)		(106,642)
Net Utility Plant in Service			**242,611**		**215,138**
Construction work in progress			3,144		7,242
Total Utility Plant		**$**	**245,755**	**$**	**222,380**

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.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2023		2022
(Thousands)				
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	2,158	$	2,457
Income taxes (refunded) paid, net	$	(2,790)	$	8,360

Of the income taxes (refunded) paid, substantially all were (refunded by) paid to AGR under the tax sharing agreement. Interest capitalized was $0.5 million in 2023 and $0.1 million in 2022, respectively. Accrued liabilities for utility plant additions were $8.7 million at December 31, 2023 and $4.1 million at December 31, 2022.

***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 $6.9 million for 2023 and $9.0 million for 2022, and are shown net of an allowance for credit losses at December 31 of $3.0 million for 2023 and $3.6 million for 2022. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $1.5 million in 2023 and $1.6 million in 2022.

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. We 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: 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: 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 our balance sheets within “Materials and supplies.” We combine inventory items for the statement of cash flow 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 the period in which we incur the expenses.

There were no government grants recorded as of December 31, 2023 and 2022.

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 2041.

***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. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers.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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the Berkshire Non-Union Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. We amortize unrecognized actuarial gains and losses in excess of 10% of the greater of PBO or market-related value of assets (MRVA) related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the Berkshire Non-Union Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. 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*:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The CAMT and other various applicable provisions of the IRA are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year, as well as on anticipated guidance from the U.S. Department of Treasury.

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, 2023 is $1.6 million. The aggregate amount of related party income tax receivable due from AGR at December 31, 2022 is $2.5 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 regulatory assets 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, 2023 and 2022.

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.

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.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2023 that are expected to have a material impact on Berkshire's financial statements.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on Berkshire's financial statements.

(a) Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance to enhance income tax disclosures. The two primary enhancements relate to disaggregation of the annual disclosures for the effective tax rate reconciliation and income taxes paid. For the rate reconciliation, it requires additional disaggregation of information in a tabular format using both percentages and amounts broken out into specific categories (e.g., state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, and changes in unrecognized tax benefits). For income taxes paid, it requires disaggregation by jurisdiction (e.g., federal, state and foreign). We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

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.

Union collective bargaining agreements: Approximately 74% of our employees are covered by collective bargaining agreements. We have approximately 86% of the collective bargaining agreements expiring during 2024.

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.

On June 24, 2022, Berkshire filed a Settlement Agreement with the Massachusetts Attorney General's Office (AGO) for DPU approval. The Settlement Agreement followed Berkshire's December 14, 2021 filing of a Notice of Intent to File Rate Schedules. Following that filing, Berkshire and the AGO negotiated the Settlement Agreement in lieu of a fully litigated rate case before the DPU. The Settlement Agreement allows for agreed-upon adjustments to Berkshire's revenue requirement as well as various step increases Berkshire shall be entitled to on January 1, 2023 and January 1, 2024. The Settlement Agreement provides that it shall be void unless approved in its entirety by the DPU by November 1, 2022. It provides for the opportunity to increase Berkshire's revenue requirement by as much as $5.6 million over current rates (reflective of a 9.70% ROE and a 54.00% equity ratio as well as other stepped adjustments) through January 1, 2024. The Settlement Agreement was approved in its entirety by the DPU on October 27, 2022, and new rates went into effect January 1, 2023.

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. Berkshire also owns or has rights to the propane stored in its on-system propane facilities, which are also directly connected 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 $15.9 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 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.

Regulatory assets at December 31, 2023 and 2022 consisted of:

December 31,		**2023**		**2022**
(Thousands)				
Deferred purchased gas	$	3,619	$	9,038
Energy efficiency programs		2,752		518
Environmental remediation costs		4,250		4,748
Pension and other postretirement benefits		13,844		14,466
Recoverable bad debt		1,300		1,537
Revenue decoupling mechanism		4,868		1,731
Unfunded future income taxes		410		597
Other		2,081		2,133
Total regulatory assets		**33,124**		**34,768**
Less: current portion		14,396		14,653
Total non-current regulatory assets	**$**	**18,728**	**$**	**20,115**

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 (EE) 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 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.

Recoverable bad debt represents the portion of uncollectible expense attributable to gas costs.

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

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 residential assistance programs.

Regulatory liabilities at December 31, 2023 and 2022 consisted of:

December 31,	**2023**	**2022**
(Thousands)		
Asset removal obligations	$ 40,091	$ 39,146
Pension and other postretirement benefits	889	1,330
Tax Act – remeasurement	11,060	11,242
Other	289	106
Total regulatory assets	**52,329**	**51,824**
Less: current portion	463	—
Total non-current regulatory assets	**$ 51,866**	**$ 51,824**

Asset 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.

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.

Other includes items such as residential assistance programs.

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, 2023 and 2022 are as follows:

Years Ended December 31,	2023	2022
(Thousands)		
Regulated operations – natural gas	$ 92,541	$ 98,469
Other (a)	229	125
Revenue from contracts with customers	**92,770**	**98,594**
Leasing revenue	—	1,044
Alternative revenue programs	3,740	2,105
Other revenue	74	14
Total operating revenues	**$ 96,584**	**$ 101,757**

(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.

We had no impairment of goodwill in 2023 and 2022 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2023 or 2022 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, 2023 and 2022, with no accumulated impairment losses and no changes during 2023 and 2022.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Current				
Federal	$	323	$	(2,200)
State		753		(353)
Current taxes charged to expense (benefit)		**1,076**		**(2,553)**
Deferred				
Federal		1,905		2,202
State		222		913
Deferred taxes charged to expense		**2,127**		**3,115**
Total Income Tax Expense	**$**	**3,203**	**$**	**562**

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, 2023 and 2022, respectively, consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Tax expense at federal statutory rate	$	2,545	$	1,399
Excess ADIT amortization		(132)		(838)
State tax expense, net of federal benefit		770		442
Other, net		20		(442)
Total Income Tax Expense	**$**	**3,203**	**$**	**562**

Income tax expense for the year ended December 31, 2023 was $0.7 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state income taxes, partially offset by excess Accumulated Deferred Income Tax (ADIT) amortization. This resulted in an effective tax rate of 26.4%. Income tax expense for the year ended December 31, 2022 was $0.8 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 income taxes. This resulted in an effective tax rate of 8.4%.

Deferred tax assets and liabilities as of December 31, 2023 and 2022 consisted of:

December 31,		2023		2022
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	33,663	$	33,138
Deferred gas and other deferred charges		—		(1,748)
2017 Tax Act measurement		(3,022)		(3,071)
Federal and state net operating loss		(2,040)		(2,399)
Pension and other postretirement benefits		313		223
Gas supply charges		1,344		2,889
Other		2,532		1,351
Total Non-current Deferred Income Tax Liabilities	**$**	**32,790**	**$**	**30,383**
Deferred tax assets		5,062		7,218
Deferred tax liabilities		37,852		37,601
Net Accumulated Deferred Income Tax Liabilities	**$**	**32,790**	**$**	**30,383**

Berkshire has federal net operating losses of $1.4 million and $1.8 million for the years ended December 31, 2023 and 2022, respectively. Berkshire has net state net operating losses of $0.6 million for the year ended December 31, 2023. Berkshire had net state net operating losses of $0.6 million for the year ended December 31,2022.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2023 and 2022.

Note 7. Long-term Debt

Long-term debt as of December 31, 2023 and 2022 consisted of:

December 31,		**2023**		**2022**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured notes	2029-2050	$ 60,000	3.68%-5.33%	$ 60,000	3.68%-5.33%
Unamortized debt issuance cost and discount		(358)		(405)	
Total Debt		**59,642**		**59,595**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 59,642**		**$ 59,595**	

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, 2023 and 2022.

Note 8. Bank Loans and Other Borrowings

Berkshire had $17.2 million notes payable as of December 31, 2023 and $9.7 million notes payable outstanding as of December 31, 2022. 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 $15.0 million outstanding under this agreement as of December 31, 2023 and $9.7 million debt outstanding as of December 31, 2022.

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 $2.2 million debt outstanding under this agreement as of December 31, 2023 and no debt outstanding under this agreement as of December 31, 2022.

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, 2023 and 2022.

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 0.34 to 1.00 at December 31, 2023. We are not in default as of December 31, 2023.

Note 9. Leases

We have operating leases for land rights. As of December 31, 2023 and 2022, 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 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,		2023		2022
(Thousands)				
Lease cost				
Operating lease cost	$	10	$	9
Short-term lease cost		35		38
Total lease cost	**$**	**45**	**$**	**47**

Balance sheet and other information for the years ended December 31, 2023 and 2022 was as follows:

As of December 31,	2023	2022
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 100	$ 105
Operating lease liabilities, current	7	7
Operating lease liabilities, long-term	92	96
Total operating lease liabilities	$ 99	$ 103
Weighted-average Remaining Lease Term (years):		
Operating leases	11.95	12.93
Weighted-average Discount Rate:		
Operating leases	2.94 %	2.46 %

Supplemental cash flows information related to leases was as follows:

For the Years Ended December 31,	2023	2022
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 9	$ 8
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 2	$ (29)

As of December 31, 2023, maturities of lease liabilities were as follows:

	Operating Leases
(Thousands)	
Years ending December 31,	
2024	$ 9
2025	9
2026	9
2027	10
2028	10
Thereafter	72
Total lease payments	**119**
Less: imputed interest	(20)
Total	**$ 99**

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, 2023 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 $0.4 million and has recorded a liability and offsetting regulatory asset for such expenses as of December 31, 2023. 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, 2023, we have accrued approximately $2.0 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 2041.

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $53 million as of December 31, 2023 and $51 million as of December 31, 2022. 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, 2023 and 2022 consisted of:

Description	Level 1	Level 2	Level 3	Total
(Thousands)				
2023				
Assets				
Non-current investments	$ 2,170	$ —	$ —	$ 2,170
Total	**$ 2,170**	**$ —**	**$ —**	**$ 2,170**
2022				
Assets				
Non-current investments	$ 1,990	$ —	$ —	$ 1,990
Total	**$ 1,990**	**$ —**	**$ —**	**$ 1,990**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2023. 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 $1.1 million in 2023 and $0.9 million in 2022.

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 $1.1 million at both December 31, 2023 and 2022.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 37,686	$ 54,066	$ 1,672	$ 1,947
Service cost	148	708	24	35
Interest cost	1,865	1,696	81	49
Curtailments	—	(1,730)	—	—
Settlements	—	(2,507)	—	—
Actuarial loss (gain)	1,435	(10,953)	483	(356)
Benefits paid	(3,699)	(3,594)	(65)	(3)
Benefit obligation at December 31	**$ 37,435**	**$ 37,686**	**$ 2,195**	**$ 1,672**
Change in plan assets				
Fair value of plan assets at January 1	26,679	40,541	—	—
Actual return on plan assets	3,351	(8,283)	—	—
Employer contributions	352	522	65	3
Settlements	—	(2,507)	—	—
Benefits paid	(3,699)	(3,594)	(65)	(3)
Fair value of plan assets at December 31	**$ 26,683**	**$ 26,679**	**$ —**	**$ —**
Funded status	**$ (10,752)**	**$ (11,007)**	**$ (2,195)**	**$ (1,672)**

During 2023, the pension benefit obligation had an actuarial loss of $1.4 million primarily due to $1.9 million loss from decreases in discount rates.There were no significant gains or losses relating to the postretirement benefit obligations in 2023.

During 2022, the pension benefit obligation had an actuarial gain of $11.0 million, primarily due to a $10.6 million gain from increases in discount rates. In 2022, the pension benefit obligation had a reduction of $2.5 million from settlements and $1.7 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. There were no significant gains or losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Other current liabilities	$ —	$ —	$ (229)	$ (168)
Pension and other postretirement benefits	(10,752)	(11,007)	(1,966)	(1,504)
Total	**$ (10,752)**	**$ (11,007)**	**$ (2,195)**	**$ (1,672)**

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	
December 31,	2023	2022	2023	2022
(Thousands)				
Net loss (gain)	$ 4,255	$ 4,950	$ (714)	$ (1,330)

Our accumulated benefit obligation for all qualified defined benefit pension plans was $36.9 million at December 31, 2023 and $37.2 million at December 31, 2022.

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, 2023 and 2022. 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, 2023 and 2022.

December 31,	2023	2022
(Thousands)		
Projected benefit obligation	$ 37,435	$ 37,686
Accumulated benefit obligation	$ 36,909	$ 37,182
Fair value of plan assets	$ 26,683	$ 26,679

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2023 and 2022.

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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	2023	2022	2023	2022
(Thousands)				
Net periodic benefit cost				
Service cost	$ 148	$ 708	$ 24	$ 35
Interest cost	1,865	1,696	81	49
Expected return on plan assets	(1,528)	(2,443)	—	—
Amortization of actuarial loss (gain)	307	132	(133)	(108)
Settlement charge	—	159	—	—
Net periodic benefit cost	**$ 792**	**$ 252**	**$ (28)**	**$ (24)**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	$ (389)	$ (225)	$ 483	$ (356)
Amortization of actuarial (loss) gain	(307)	(132)	113	108
Curtailment charge	—	(1,731)	—	—
Settlement charge	—	(159)	—	—
Total recognized in regulatory assets and regulatory liabilities	**(696)**	**(2,247)**	**596**	**(248)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ 96**	**$ (1,995)**	**$ 568**	**$ (272)**

Notes to Financial Statements

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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
Discount rate	4.69%	5.21%	4.66%	5.08%
Rate of compensation increase	2.50% for Union	N/A / 2.50%	N/A	N/A
Interest crediting rate	2.75%	4.48% / 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 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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
Discount rate	5.21%	2.96% / 4.15%	5.08%	2.61%
Expected long-term return on plan assets	7.50%	7.00%	N/A	N/A
Rate of compensation increase	2.50% for Union	3.50% / N/A / 2.50%	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 in excess of 10% of the greater of PBO or MRVA related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the Berkshire Non-Union Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2023 and 2022 consisted of:

As of December 31,	**2023**	**2022**
Health care cost trend rate (pre 65/post 65)	8.10% / 8.60%	6.00% / 6.50%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50% / 4.50%	4.50% / 4.50%
Year that the rate reaches the ultimate trend rate	2031 / 2032	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 $2 million to our pension and $0.2 million to our other postretirement benefit plans during 2024.

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
2024	$ 3,544	$ 229	$ —
2025	$ 3,030	$ 253	$ —
2026	$ 3,082	$ 258	$ —
2027	$ 3,096	$ 246	$ —
2028	$ 2,854	$ 229	$ —
2029 - 2033	$ 13,450	$ 856	$ —

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 15%-70% for Return-Seeking assets and 30%-85% 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, 2023, consisted of:

Asset Category	Total	Level 1	Level 2	Level 3
(Thousands)				
2023				
Cash and cash equivalents	$ 636	$ 22	$ 614	$ —
U.S. government securities	2,864	2,864	—	—
Common stocks	1,231	1,231	—	—
Registered investment companies	1,398	1,398	—	—
Corporate bonds	7,046	—	7,046	—
Common collective trusts	10,151	—	10,151	—
Other investments, principally annuity and fixed income	(883)	(1)	(882)	—
	$ 22,443	**$ 5,514**	**$ 16,929**	**$ —**
Other investments measured at net asset value	4,240			
Total	**$ 26,683**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Level 1**	**Level 2**	**Level 3**
(Thousands)				
2022				
Cash and cash equivalents	$ 1,240	$ 3	$ 1,237	$ —
U.S. government securities	1,395	1,395	—	—
Common stocks	1,156	1,156	—	—
Registered investment companies	1,290	1,290	—	—
Corporate bonds	7,026	—	7,026	—
Preferred stocks	7	7	—	—
Common collective trusts	9,528	—	9,528	—
Other investments, principally annuity and fixed income	92	—	92	—
	$ 21,734	**$ 3,851**	**$ 17,883**	**$ —**
Other investments measured at net asset value	4,945			
Total	**$ 26,679**			

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, 2023 and 2022.

Note 13. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2023 and 2022, consisted of:

Years Ended December 31,		**2023**		**2022**
(Thousands)				
Allowance for funds used during construction	$	39	$	5
Carrying costs on regulatory assets		1,073		858
Miscellaneous		(48)		(4)
Total other income	**$**	**1,064**	**$**	**859**
Pension non-service components		129		(414)
Miscellaneous		(462)		(558)
Total other deductions	**$**	**(333)**	**$**	**(972)**

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 $6.7 million in 2023 and $4.9 million in 2022. Cost for services includes amounts capitalized in utility plant, which was approximately $0.5 million in 2023 and $0.1 million in 2022. The remainder was primarily recorded as operations and maintenance expense. There were no charges for services provided by Berkshire to AGR in 2023. The charge for services provided by Berkshire to AGR and its subsidiaries was approximately $0.1 million in 2022. 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 balances in accounts payable to affiliates of $5.4 million at December 31, 2023 and $1.0 million at December 31, 2022 are mostly payable to UIL Holdings and Avangrid Service Company.

Note 15. Subsequent Events

The company has performed a review of subsequent events through March 29, 2024, which is the date these financial statements were available to be issued.

New York State Electric & Gas Corporation

Financial Statements

As of and for the Years Ended December 31, 2023 and 2022

New York State Electric & Gas Corporation

Index

Page(s)

Financial Statements As of and for the Years Ended December 31, 2023 and 2022

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

Independent Auditors' Report

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

Opinion

We have audited the financial statements of New York State Electric and Gas Corporation (the Company), which comprise the balance sheets as of December 31, 2023 and 2022, 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, 2023 and 2022, 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 available to be 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, 2024

New York State Electric & Gas Corporation
Statements of Income

Years Ended December 31,	2023	2022
(Thousands)		
Operating Revenues	$ 2,196,936	$ 2,220,777
Operating Expenses		
Electricity purchased	513,155	675,965
Natural gas purchased	127,177	183,584
Operations and maintenance	907,062	793,570
Depreciation and amortization	208,969	190,719
Taxes other than income taxes, net	161,089	169,289
Total Operating Expenses	**1,917,452**	**2,013,127**
Operating Income	**279,484**	**207,650**
Other income	49,638	38,842
Other (deductions) income, net	13,628	(11,951)
Interest expense, net of capitalization	(86,858)	(61,634)
Income Before Income Tax	**255,892**	**172,907**
Income tax expense	43,657	15,879
Net Income	**$ 212,235**	**$ 157,028**

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,	2023	2022
(Thousands)		
Net Income	**$ 212,235**	**$ 157,028**
Other Comprehensive Income (Loss), Net of Tax		
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of income tax	24	286
Unrealized gain during the year on derivatives qualifying as cash flow hedges, net of income tax	—	1,002
Reclassification to net income of gain on settled cash flow commodity hedges, net of income tax	—	(1,026)
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax	227	87
Total Other Comprehensive Income, Net of Tax	**251**	**349**
Comprehensive Income	**$ 212,486**	**$ 157,377**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2023	2022
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 6,101	$ 1
Accounts receivable and unbilled revenues, net	348,556	430,952
Accounts receivable from affiliates	4,900	3,726
Fuel and natural gas in storage	19,022	55,701
Materials and supplies	47,037	32,870
Broker margin accounts	12,039	32,425
Prepaid property taxes	38,757	38,020
Other current assets	19,695	11,136
Regulatory assets	204,332	141,420
Total Current Assets	**700,439**	**746,251**
Utility plant, at original cost	8,528,387	7,967,438
Less accumulated depreciation	(2,490,347)	(2,410,717)
Net Utility Plant in Service	**6,038,040**	**5,556,721**
Construction work in progress	882,447	674,505
Total Utility Plant	**6,920,487**	**6,231,226**
Operating lease right-of-use assets	8,202	9,022
Other property and investments	8,779	8,262
Regulatory and Other Assets		
Regulatory assets	1,050,289	830,199
Other	40,526	43,739
Total Regulatory and Other Assets	**1,090,815**	**873,938**
Total Assets	**$ 8,728,722**	**$ 7,868,699**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2023	2022
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$ 9,603	$ 298,492
Notes payable to affiliates	83,300	89,800
Accounts payable and accrued liabilities	565,373	615,117
Accounts payable to affiliates	120,564	113,221
Interest accrued	29,288	13,345
Taxes accrued	9,712	2,380
Operating lease liabilities	1,237	1,293
Derivative liabilities	—	21
Environmental remediation costs	6,061	14,254
Customer deposits	13,858	13,300
Regulatory liabilities	75,587	67,048
Other	110,600	162,432
Total Current Liabilities	**1,025,183**	**1,390,703**
Regulatory and Other Liabilities		
Regulatory liabilities	917,132	1,040,544
Other Non-current Liabilities		
Deferred income taxes	853,843	770,556
Pension and other postretirement	119,885	87,538
Operating lease liabilities	8,034	8,573
Asset retirement obligation	11,078	11,349
Environmental remediation costs	53,233	62,828
Other	24,119	26,180
Total Regulatory and Other Liabilities	**1,987,324**	**2,007,568**
Non-current debt	2,875,190	2,041,562
Total Liabilities	**5,887,697**	**5,439,833**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 64,508,477 shares outstanding at December 31, 2023 and 2022)	430,057	430,057
Additional paid-in capital	1,929,142	1,529,469
Retained earnings	482,395	470,160
Accumulated other comprehensive loss	(569)	(820)
Total Common Stock Equity	**2,841,025**	**2,428,866**
Total Liabilities and Equity	**$ 8,728,722**	**$ 7,868,699**

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,	2023	2022
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 212,235**	**$ 157,028**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	208,969	190,719
Regulatory assets/liabilities amortization	6,029	(98,703)
Regulatory assets/liabilities carrying cost	(7,899)	(6,333)
Amortization of debt issuance costs	2,947	2,036
Deferred taxes	52,984	64,665
Pension cost	(14,315)	24,685
Stock-based compensation	(15)	520
Accretion expenses	596	608
Gain from disposal of property	(759)	(3,200)
Other non-cash items	(74,446)	(71,636)
Changes in assets and liabilities		
Accounts receivable, from affiliates, and unbilled revenues	81,222	(131,164)
Inventories	22,512	(41,440)
Accounts payable, to affiliates, and accrued liabilities	(96,732)	90,290
Taxes accrued	7,334	(37,130)
Other assets/liabilities	(46,256)	107,958
Regulatory assets/liabilities	(289,537)	(190,907)
Net Cash Provided by Operating Activities	**64,869**	**57,996**
Cash Flow from Investing Activities:		
Capital expenditures	(838,955)	(685,078)
Contributions in aid of construction	39,731	45,420
Proceeds from sale of property, plant and equipment	5,376	7,224
Net Cash Used in Investing Activities	**(793,848)**	**(632,434)**
Cash Flow from Financing Activities:		
Non-current debt issuance	841,791	342,623
Repayments of non-current debt	(300,000)	(75,000)
Payments of finance leases	(212)	(3,185)
Notes payable to affiliates	(6,500)	10,000
Capital contribution	400,000	475,000
Dividends paid	(200,000)	(175,000)
Net Cash Provided by Financing Activities	**735,079**	**574,438**
Net Increase in Cash and Cash Equivalents	**6,100**	**—**
Cash and Cash Equivalents, Beginning of Year	**1**	**1**
Cash and Cash Equivalents, End of Year	**$ 6,101**	**$ 1**

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, 2021	**64,508,477**	**$ 430,057**	**$ 1,054,042**	**$ 488,132**	**$ (1,169)**	**$ 1,971,062**
Net income	—	—	—	157,028	—	157,028
Other comprehensive income, net of tax	—	—	—	—	349	349
Comprehensive income						157,377
Stock-based compensation	—	—	427	—	—	427
Common stock dividends	—	—	—	(175,000)	—	(175,000)
Capital contribution	—	—	475,000	—	—	475,000
Balance, December 31, 2022	**64,508,477**	**430,057**	**1,529,469**	**470,160**	**(820)**	**2,428,866**
Net income	—	—	—	212,235	—	212,235
Other comprehensive income, net of tax	—	—	—	—	251	251
Comprehensive income						212,486
Stock-based compensation	—	—	(327)	—	—	(327)
Common stock dividends	—	—	—	(200,000)	—	(200,000)
Capital contribution	—	—	400,000	—	—	400,000
Balance, December 31, 2023	**64,508,477**	**$ 430,057**	**$ 1,929,142**	**$ 482,395**	**$ (569)**	**$ 2,841,025**

(*) 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 919,000 electricity and 271,000 natural gas customers as of December 31, 2023, 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 81.6% 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 primarily 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 2.4% of average depreciable property for 2023 and 2.3% of average depreciable property for 2022. 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 $314.8 million as of December 31, 2023 and $275.6 million as of December 31, 2022. Depreciation expense was $193.9 million in 2023 and $176.2 million in 2022. Amortization of capitalized software was $15.0 million in 2023 and $14.5 million in 2022.

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)**	**2023**	**2022**
(Thousands)			
Electric	2-80	$ 6,021,282	$ 5,646,997
Natural Gas	2-75	1,380,310	1,309,408
Common	7-70	1,126,795	1,011,033
Total Utility Plant in Service		**8,528,387**	**7,967,438**
Total accumulated depreciation		(2,490,347)	(2,410,717)
Total Net Utility Plant in Service		**6,038,040**	**5,556,721**
Construction work in progress		882,447	674,505
Total Utility Plant		**$ 6,920,487**	**$ 6,231,226**

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. If the amounts in OCI are probable of recovery in the ratemaking process, then the OCI is reclassified as a regulatory asset or liability. 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.

Notes to Financial Statements

***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.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2023		2022
(Thousands)				
Cash paid (refunded) during the years ended December 31:				
Interest, net of amounts capitalized	$	73,048	$	55,562
Income taxes refunded, net	$	(17,250)	$	(12,859)

Of the income taxes refunded, substantially all was refunded by AGR under the tax sharing agreement. Interest capitalized was $16.9 million in 2023 and in $10.8 million in 2022. Accrued liabilities for utility plant additions were $151.5 million and $98.3 million as of December 31, 2023 and 2022, respectively.

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 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 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 $101.4 million for 2023 and $119.7 million for 2022, and are shown net of an allowance for credit losses at December 31 of $62.8 million for 2023 and $52.6 million for 2022. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $62.1 million in 2023, including $19.3 million of arrears forgiveness balances. Credit loss expense was $47.7 million in 2022, including $24.5

million of arrears forgiveness balances. Arrears forgiveness balances will be recovered through a tariff over a three year period that began August 1, 2022 for Phase 1 and a two and a half year-period that began on March 1, 2023 for Phase 2.

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. We 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 $17.6 million for 2023 and $13.6 million for 2022. DPA receivable balances at December 31 were $39.1 million for 2023 and $28.2 million for 2022.

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.”

Notes to Financial Statements

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.

The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2023 and 2022 consisted of:

(Thousands)	Government grants	Total
As of December 31, 2021	**$ 11,074**	**$ 11,074**
Disposals	—	—
Recognized in income	(291)	(291)
As of December 31, 2022	**$ 10,783**	**$ 10,783**
Disposals	—	—
Recognized in income	(291)	(291)
As of December 31, 2023	**$ 10,492**	**$ 10,492**

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the government. We believe we are in compliance with each grant's terms and conditions as of December 31, 2023 and 2022.

Deferred income: Apart from government grants, we occasionally receive payments from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such payments 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 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, 2023 and 2022.

Years ended December 31,		2023		2022
(Thousands)				
ARO, beginning of year	$	11,349	$	11,583
Liabilities settled during the year		(867)		(842)
Accretion expense		596		608
ARO, end of year	**$**	**11,078**	**$**	**11,349**

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. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 by assigning an equal amount to each future period of service of each employee active on the date of the amendment who is expected to receive benefits under the plan. Prior service cost changes resulting from union bargaining agreements are amortized on a straight-line basis over the period from first recognition to the end of the bargaining agreement. 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**:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax (“CAMT”) of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The CAMT and other various applicable provisions of the IRA are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year, as well as on anticipated guidance from the U.S. Department of Treasury.

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 $5.5 million and $0.1 million at December 31, 2023 and 2022, 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 regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit 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, 2023 and 2022.

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. We consider the effect of the alternative minimum tax system in determining the need for a valuation allowance for deferred taxes. 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.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2023 that are expected to have a material impact on NYSEG’s financial statements.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on NYSEG’s financial statements.

(a) Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance to enhance income tax disclosures. The two primary enhancements relate to disaggregation of the annual disclosures for the effective tax rate reconciliation and income taxes paid. For the rate reconciliation, it requires additional disaggregation of information in a tabular format using both percentages and amounts broken out into specific categories (e.g., state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, and changes in unrecognized tax benefits). For income taxes paid, it requires disaggregation by jurisdiction (e.g., federal, state and foreign). We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

Notes to Financial Statements

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.

Union collective bargaining agreements: Approximately 74% of our employees are covered by a collective bargaining agreement, which will expire during 2024.

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.

2020 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.

The Proposal provides that with few exceptions, the provisions for electric and gas service under the Proposal for Rate Year 3 (the twelve-month period ending April 30, 2023) shall continue unless and until such provisions and base delivery rates for electric or gas service are changed by subsequent order of the New York Public Service Commission. Thus, from May 1, 2023, until such time as new rates are approved by the Commission, the current rates and terms for Rate Year 3 of the prior Proposal remain in effect.

2023 NYSEG Rate Plan

On May 26, 2022, NYSEG made an initial filing to the NYPSC requesting increases to the delivery rates for its electric business of 31.2% and for its gas business of 20.7%. This initial filing started a lengthy process guided by NYPSC regulations. The Department of Public Service Staff and other parties to the rate cases submitted testimony on September 26, 2022. On October 18, 2022, the Companies submitted rebuttal testimony responding to the testimony of Department of Public Service Staff and other parties to the proceedings. On October 19, 2022, the Companies filed a notice of impending settlement negotiations. A Joint Proposal for a three year rate plan term for electric and gas service at NYSEG commencing May 1, 2023 and continuing through April 30, 2026 was filed on June 14, 2023. The NYPSC issued an Order on October 12, 2023 approving the Joint Proposal in its entirety with one modification to acknowledge that the "make whole" period would be effective from May 1, 2023 through November 1, 2023, rather than October 1, 2023, as originally proposed in the Joint Proposal. The effective date of new tariffs was November 1, 2023 with make-whole back to May 1, 2023. The Joint Proposal bases delivery revenues on an 9.20% 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 eight parties, and includes levelized delivery rate increases as summarized below:

	May 1, 2023		May 1, 2024		May 1, 2025	
	Rate Increase (Millions)	Delivery Rate Increase* %	Rate Increase (Millions)	Delivery Rate Increase* %	Rate Increase (Millions)	Delivery Rate Increase* %
Electric	$137.3	17.1%	$160.7	17.1%	$200.6	17.1%
Gas	$11.7	5.6%	$12.4	5.6%	$12.9	5.6%

* Based on "net base delivery" revenues, which consist of gross base delivery revenue plus Bill Issuance Payment Process (BIPP), plus Gross Revenue Tax (GRT).

The approved Joint Proposal also reflects increased energy efficiency programs and distribution vegetation management, along with investments in aging infrastructure, resiliency, continued implementation of Advanced Metering Infrastructure (AMI), and increases in the Company's workforce. The approved Joint Proposal reflects the continued recovery of deferred NYSEG Electric storm costs and continued reserve accounting for qualifying Major Storms ($31.5 million in Rate Year 1, $41.5M in Rate Year 2 and $46.5M in Rate Year 3). 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 continued part of the 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 approved Joint Proposal modified the Tier II SAIFI targets to make them more achievable. The Proposal also maintains 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, with increases to potential negative revenue adjustments. The approved Joint Proposal continues bill reduction and arrears forgiveness Low Income Programs. Certain 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) costs associated with the implementation of any Commission-ordered EV program which are not covered by any other cost recovery mechanism; and (6) Covid-related uncollectibles (Rate Years 1 and 2 only).

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; Low Income Programs, and Covid-related Uncollectible Expense. The Proposal also includes downward-only Net Plant, AMI and Resiliency Program 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 the Company continue the electric and gas revenue decoupling mechanisms (RDM) on a total revenue per class basis.

The Proposal provides that with few exceptions, the provisions for electric and gas service under the Proposal for Rate Year 3 (the twelve-month period ending April 30, 2026) shall continue unless and until such provisions and base delivery rates for electric or gas service are changed by subsequent order of the New York Public Service Commission. Thus, from May 1, 2023, until such time as new rates are approved by the Commission, the current rates and terms for Rate Year 3 of the prior Proposal remain in effect.

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 was 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 (DER), such as micro grids, on-site power supplies and storage.

The NYPSC issued a 2015 order in Track 1, which acknowledged the utilities’ role as a Distribution System Platform provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) followed by bi-annual updates. The next scheduled DSIP update is June 30, 2025.

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. EAMs were approved by the Commission on November 19, 2020 in its Order approving the companies' 2020 Rate Plan. Modifications to EAMs were approved by the Commission on October 12, 2023 in its Order approving the companies' 2023 Rate Plan.

In 2017, the NYPSC approved a transition from traditional Net Energy Metering (NEM) towards a more values-based approach (Value Stack) for compensating DER. Since that time, the Commission has issued a number of orders on additional Value of Distributed Energy Resources matters. Most recently, the NYPSC Staff issued a proposal on Community Distributed Generation (CDG) Billing and Crediting Performance Metrics and Negative Revenue Adjustments (NRA). The NYPSC Staff recommends six CDG performance metrics with associated NRAs that would incent improvements to the CDG billing processes. At this time, the outcome of this proceeding is unknown.

Other REV-related orders pertaining to electric vehicles (EV), an Integrated Energy Data Resource (IEDR) platform and energy storage are summarized below.

- The NYPSC issued an Order on April 20, 2023 instituting a proceeding to advance infrastructure for medium and heavy-duty vehicles. The Joint Utilities filed an implementation plan with the NYPSC for the medium and heavy-duty pilot program. The Joint Utilities are awaiting the NYPSC's approval of the implementation plan.

- On February 11, 2021, the NYPSC issued an Order to implement an Integrated Energy Data Resource platform, where NYSERDA was designated as the Program Sponsor of the platform. 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 January 19, 2024, the NYPSC issued an Order approving Phase 2 budget, with costs up to the combined cost cap deferred for future recovery in the same manner as Phase 1.

- An order 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 EV charging stations.

- On December 13, 2018, the NYPSC issued an Order for utilities to file implementation plans detailing a competitive procurement process and cost recovery for deploying qualified storage systems. NYSEG and RG&E have tariffs in effect to collect costs for the procurement of qualified energy storage assets.

Customer Arrearages Reduction Order

On June 16, 2022, the NYPSC issued an order (Phase 1) authorizing an arrears reduction program targeting low-income customers to provide COVID-19-related relief through a one-time bill credit to eliminate accrued arrears through May 1, 2022. A portion of the targeted arrearages will be funded via direct contributions from the State of New York, and the remainder to be received via a surcharge to all customers. The surcharge recovery is over three years for NYSEG beginning on August 1, 2022.

On January 19, 2023, the NYPSC issued a subsequent order (Phase 2) providing bill relief for customers who did not receive a credit as part of the Phase 1 Program approved in 2022 (Low Income Program participants). Qualifying residential and small business customers are eligible to have any past-due balance from bills for service through May 1, 2022, reduced through a one time bill credit, up to a maximum credit below:

Residential	Total Forecast Residential Credits (Millions)	Small Business	Total Forecast Small Business Credits (Millions)
Up to $1,000	$16.9	Up to $1,250	$1.4

The New York State Budget for 2023-2024 included an appropriation of $200 million designated to provide prompt utility bill relief. On February 15, 2024, the NYPSC issued an order authorizing and directing utilities, including NYSEG, to provide one-time bill credits to customers to achieve the stated purpose of the budget appropriation. The February 15, 2024 NYPSC Order provides $8.7 million and $4.3 million, for NYSEG Electric and Gas customers, respectively, to be distributed in the form of one-time credits to customers as shown below:

Service	Number of Customers	NYSEG Allocation (Millions)	Estimated Credit Per Customer
Electric	916,528	$8.7	$9.5
Gas	271,630	$4.3	$15.7

Community Leadership and Climate Protection Act Transmission

Pursuant to the Community Leadership and Climate Protection Act of 2019 (CLCPA) and Accelerated Renewable Energy Growth and Community Benefit Act of 2020, the Commission has issued orders addressing investment in transmission by NYSEG to support the state achieving the CLCPA's goal of 70% renewable energy by 2030. First, on December 15, 2022, the Commission issued an Order authorizing NYSEG to continue the development of CLCPA "Phase 1" transmission projects with an estimated investment of approximately $1.27 billion through 2030. CLCPA Phase 1 transmission projects are upgrades to the NYSEG local transmission system that are being developed to satisfy reliability needs, but that also create headroom on the transmission system for the interconnection and delivery of new generation sources. The December 15, 2022 Order allows NYSEG to continue development of the projects while the rate case is pending, with any final project approvals to be addressed in the rate case.

Second, on February 16, 2023, the Commission issued an Order approving the investment of approximately $2.05 billion by NYSEG through 2030 in CLCPA "Phase 2" transmission projects. Phase 2 transmission projects are upgrades to the NYSEG local transmission system that are being developed primarily to allow for the interconnection and delivery of renewable energy in the Southern Tier, an area that the Commission has designated as an "Area of Concern" for renewable energy development because there is substantial renewable energy development interest but inadequate transmission. Unlike other transmission owned by NYSEG, the cost of CLCPA Phase 2 transmission will be recovered pursuant to a formula rate under the jurisdiction of the Federal Energy Regulatory Commission (FERC) so that costs can be allocated statewide. NYSEG and other transmission-owning utilities in New York negotiated a Cost Sharing and Recovery Agreement (CSRA), which was approved by the Commission on May 12, 2022, and by FERC on August 22, 2022. Under the terms of the CSRA the cost of CLCPA Phase 2 transmission projects approved by the Commission will be recovered through the New York Independent System Operator tariff, with ROE and capital structure determined by the Commission, subject to an ROE ceiling set by FERC.

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 $194.6 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 October 12, 2023, the NYPSC approved the Proposal in connection with a three-year rate plan for electric and gas service at NYSEG effective May 1, 2023. Following the approval of the proposal most of these items related to NYSEG are amortized over a three-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 three years. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, annual net amortization revenue for NYSEG is approximately $44.9 million for the year ended December 31, 2023.

Regulatory assets at December 31, 2023 and 2022 consisted of:

December 31,	2023	2022
(Thousands)		
Asset retirement obligation	$ 11,303	$ 11,550
COVID-19 late payment surcharge	—	2,669
Electric supply reconciliation	4,991	18,927
Environmental remediation costs	47,167	50,332
Energy efficiency programs	8,967	—
Federal tax depreciation normalization adjustment	75,627	79,411
Low income programs	12,701	14,252
Low income arrears forgiveness	24,066	14,332
Make-whole provision	63,342	—
Pension and other post-retirement benefits	99,656	62,615
Pension and other post-retirement benefits cost deferrals	16,559	40,783
Rate adjustment mechanism	15,734	33,158
Rate change levelization	38,572	—
Revenue decoupling mechanism	14,095	4,479
Sales and use tax audit deferral	9,269	17,911
Storm costs	529,811	456,467
Unamortized loss on re-acquired debt	9,686	11,411
Uncollectible reserve	61,661	—
Unfunded future income taxes	17,758	8,972
Value distributed energy resource	32,617	24,810
Vegetation management	69,859	61,611
Other	91,180	57,929
Total regulatory assets	**1,254,621**	**971,619**
Less: current portion	204,332	141,420
Total non-current regulatory assets	**$ 1,050,289**	**$ 830,199**

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 late payment surcharge represents deferred lost late payment revenue in the state of New York based on the order issued by PSC on June 17, 2022, approving deferral and surcharge/sur-credit mechanism to recover/return deferred balances starting July 1, 2022.

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.

Energy efficiency 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.

Federal tax depreciation normalization adjustment represents the revenue requirement impact of the difference in the deferred income tax expense required to be recorded under the IRS normalization rules and the amount of deferred income tax expense that was included in cost of service for rate years covering 2011 forward. The recovery period is being amortized over a twenty-year period starting in 2023.

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

Low income arrears forgiveness represents deferred bill credits in the state of New York based on the order issued by PSC on June 16, 2022, approving deferral of bill credits for low-income customers (Phase 1), and additional deferred bill credits for other residential and small commercial customers who did not qualify for Phase 1 based on the order issued by PSC on January 19, 2023 (Phase 2). The Phase 1 regulatory asset will be recovered from all customers over three years for NYSEG through a surcharge that began August 1, 2022. The Phase 2 regulatory asset will be recovered from all customers over two and a half years for NYSEG through a surcharge that began March 1, 2023.

Make-whole provision represents the regulatory asset to recover revenues that would have been received by NYSEG had Rate Year 1 rates approved in the 22-E-0317 et al. joint proposal gone into effect on the effective date of May 1, 2023. The balance is being recovered through a separately stated make-whole rate, effective November 1, 2022, over 6-30 months.

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, the remaining portion 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 and REV costs and fees not covered in other recovery mechanisms.

Rate change levelization adjusts the New York delivery rate increases across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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

Sales and Use tax audit deferral represents sales and use tax refunds allocated to operating expenses. This balance is being amortized in current rates over a six-year period beginning in 2023.

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 $529.8 million at December 31, 2023 and $456.5 million at December 31, 2022. Pursuant to the most recent Joint Proposal approved by the Commission, which began May 1, 2023, NYSEG will recover $96.6 million of the balance over seven years and $187.7 million of the balance over ten years for non-super storms, and $52.3 million of the balance over seven 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.

Uncollectible reserve includes the anticipated future rate recovery of costs that are recorded as uncollectible since those will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future uncollectible expense, it does not accrue carrying costs and is not included within rate base. It also includes the variance between actual uncollectible expense and uncollectible expense included in rates that is eligible for future recovery in customer rates. The amortization period will be established in future proceedings.

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.

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 AMI accelerated depreciation, earnings adjustment mechanism, and electric vehicle deferrals.

Regulatory liabilities at December 31, 2023 and 2022 consisted of:

December 31, (Thousands)		2023		2022
Accrued removal obligation	$	430,834	$	472,647
Accumulated deferred investment tax credits		10,554		11,197
Debt rate reconciliation		17,830		26,611
Economic development		—		6,546
Energy efficiency programs		—		8,833
Gas supply charge and deferred natural gas cost		7,022		14,514
Merchant function charge		—		188
New York 2018 winter storm settlement		160		2,881
Non by-passable charges		9,076		5,482
Pension and other postretirement benefits		37,088		48,159
Pension and other postretirement benefits cost deferral		11,330		13,261
Property tax		5,238		4,161
Rate change levelization		—		13,329
Service quality performance mechanism		38,717		30,788
Tax Act remeasurement		356,074		378,015
Unfunded future income taxes		1,076		1,398
Other		67,720		69,582
Total regulatory liabilities		**992,719**		**1,107,592**
Less: current portion		75,587		67,048
Total non-current regulatory liabilities	**$**	**917,132**	**$**	**1,040,544**

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.

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. 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 2023.

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. 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 2023.

Gas supply charge and deferred natural gas cost reflects the actual costs of purchasing, transporting, and storing of natural gas. Gas supply reconciliation is determined by comparing actual gas supply expenses to the monthly gas cost recoveries in rates. Prior rate year balances are collected/returned to customers beginning the next calendar year.

Merchant function charge (MFC) deferral represents the difference of administrative cost to procure electricity supply on customers behalf and MFC revenues collected in rates.

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 2023.

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. Recovery of these amounts will be determined in future proceedings.

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.

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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.

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 Clean Energy Fund (CEF), Net Plant Reconciliation, Methane Detection Program and Direct Current Fast Charging (DCFC).

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 $17.4 million at December 31, 2023 and $31.9 million at December 31, 2022, and are presented in "Other current liabilities" on our balance sheets. We recognized $43.7 million and $32.4 million as revenue during the years ended December 31, 2023 and 2022, 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, 2023 and 2022 are as follows:

Years Ended December 31,	2023	2022
(Thousands)		
Regulated operations – electricity	$ 1,768,816	$ 1,740,129
Regulated operations – natural gas	362,304	410,137
Other(a)	21,440	38,727
Revenue from contracts with customers	**2,152,560**	**2,188,993**
Leasing revenue	919	1,152
Alternative revenue programs	24,188	17,346
Other revenue	19,269	13,286
Total operating revenues	**$ 2,196,936**	**$ 2,220,777**

(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, 2023 and 2022 consisted of:

Years Ended December 31,	2023	2022
(Thousands)		
Current		
Federal	$ (8,990)	$ (41,402)
State	(337)	(7,384)
Current taxes charged to benefit	**(9,327)**	**(48,786)**
Deferred		
Federal	39,354	46,233
State	14,140	18,942
Deferred taxes charged to expense	**53,494**	**65,175**
Investment tax credit adjustments	(510)	(510)
Total Income Tax Expense	**$ 43,657**	**$ 15,879**

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, 2023 and 2022, respectively, consisted of:

Notes to Financial Statements

Years Ended December 31,		2023		2022
(Thousands)				
Tax expense at statutory rate	$	53,737	$	36,310
Equity AFUDC tax effects		(4,535)		(4,507)
Excess ADIT giveback		(16,354)		(24,682)
Investment tax credit amortization		(510)		(510)
State tax expense, net of federal benefit		10,904		9,131
Other, net		415		137
Total Income Tax Expense	**$**	**43,657**	**$**	**15,879**

Income tax expense for the year ended December 31, 2023 was $10.1 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess Accumulated Deferred Income Tax (ADIT) amortization and AFUDC Equity tax effects, partially offset by state taxes. This resulted in an effective tax rate of 17.1%. Income tax expense for the year ended December 31, 2022 was $20.4 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 9.2%.

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, 2023 and 2022 consisted of:

December 31,		2023		2022
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	957,039	$	862,600
Storm costs		138,998		123,956
Pension and other post-retirement benefits		(11,074)		(9,709)
Power tax deferred income tax		19,841		20,833
Regulatory liability due to "Tax Cuts and Jobs Act"		(93,423)		(99,171)
Environmental		(15,556)		(20,222)
Federal and state NOL's		(214,429)		(120,618)
Other		72,447		12,887
Total Non-current Deferred Income Tax Liabilities	**$**	**853,843**	**$**	**770,556**
Deferred tax assets	$	334,482	$	249,720
Deferred tax liabilities		1,188,325		1,020,276
Net Accumulated Deferred Income Tax Liabilities	**$**	**853,843**	**$**	**770,556**

NYSEG has gross federal net operating losses of $743.0 million and gross NY state net operating losses of $1,115.5 million for the year ended December 31, 2023. NYSEG had gross federal net operating losses of $410.8 million and gross NY state net operating losses of $658.2 million for the year ended December 31, 2022.

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, 2023 and 2022 consisted of:

Years Ended December 31,	**2023**	**2022**
(Thousands)		
Balance as of January 1	$ 44,978	$ 45,051
Reduction for tax positions related to prior years	(73)	(73)
Balance as of December 31	**$ 44,905**	**$ 44,978**

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, 2023 and 2022.

Note 6. Long-term Debt

Long-term debt as of December 31, 2023 and 2022 consisted of:

As of December 31,		**2023**		**2022**	
(Thousands, except interest rates)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2026-2052	$ 2,450,000	1.95%-5.85%	$ 1,900,000	1.95% - 5.75%
Unsecured pollution control notes – fixed	2024-2034	453,210	1.40% - 4.00%	453,210	1.40% - 4.00%
Unamortized debt issuance costs and discount		(18,417)		(13,156)	
Total Debt		**$2,884,793**		**$2,340,054**	
Less: debt due within one year, included in current liabilities		9,603		298,492	
Total Non-current Debt		**$ 2,875,190**		**$ 2,041,562**	

On April 6, 2022, NYSEG issued $67 million aggregate principal amount of unsecured, tax-exempt pollution control notes maturing in 2028 at an interest of 4.00%.

On December 15, 2022, NYSEG issued $150 million aggregate principal amount of unsecured notes maturing in 2032 at an interest of 4.62%.

On December 15, 2022, NYSEG issued $125 million aggregate principal amount of unsecured notes maturing in 2052 at an interest of 4.96%.

On June 21, 2023 NYSEG issued $100 million aggregate principal amount of unsecured, tax-exempt bond maturing in 2034 at an interest of 4.00%.

On August 3, 2023 NYSEG issued $350 million aggregate principal amount of unsecured green public bond maturing in 2028 at an interest of 5.65%.

On August 3, 2023 NYSEG issued $400 million aggregate principal amount of unsecured green public bond maturing in 2033 at an interest of 5.85%.

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

2024	2025	2026	2027	2028	Total
(Thousands)					
$9,603	$—	$565,000	$34,000	$417,210	$1,025,813

Note 7. Bank Loans and Other Borrowings

NYSEG had $83.3 million notes payable at December 31, 2023 and $89.8 million notes payable at December 31, 2022, 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 $20.9 million outstanding under this agreement at December 31, 2023 and $16.1 million outstanding under this agreement at December 31, 2022, 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 $62.4 million outstanding under this agreement at December 31, 2023 and $73.7 million outstanding under this agreement at December 31, 2022, 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, 2023 and December 31, 2022.

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 0.51 to 1.00 at December 31, 2023. We are not in default as of December 31, 2023.

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

At December 31, 2023 and 2022, 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 48 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,	**2023**	**2022**
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 3,503	$ 3,216
Interest on lease liabilities	122	133
Total finance lease cost	3,625	3,349
Operating lease cost	1,429	1,567
Short-term lease cost	1,494	1,430
Variable lease cost	15	24
Intercompany	(72)	(71)
Total lease cost	**$ 6,491**	**$ 6,299**

Balance sheet and other information for the years ended December 31, 2023 and 2022 was as follows:

Notes to Financial Statements

As of December 31,		2023		2022
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right of use assets	$	8,202	$	9,022
Operating lease liabilities, current		1,237		1,293
Operating lease liabilities, long-term		8,034		8,573
Total operating lease liabilities	$	9,271	$	9,866
Finance Leases				
Other assets	$	28,235	$	31,738
Other current liabilities		230		230
Other non-current liabilities		1,479		1,691
Total finance lease liabilities	$	1,709	$	1,921
Weighted-average Remaining Lease Term (years):				
Finance leases		6.89		8.11
Operating leases		9.28		9.51
Weighted-average Discount Rate:				
Finance leases		5.65 %		5.70 %
Operating leases		3.51 %		3.26 %

Supplemental cash flows information related to leases was as follows:

Years Ended December 31,		2023		2022
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	1,497	$	1,280
Operating cash flows from finance leases	$	108	$	133
Financing cash flows from finance leases	$	212	$	3,185
Right-of-use assets obtained in exchange for lease obligations:				
Finance leases	$	—	$	(13)
Operating leases	$	431	$	4,650

Maturities of lease liabilities were as follows:

(Thousands)	Finance	Operating
Years Ended December 31,		
2024	$ 333	$ 1,403
2025	324	1,361
2026	401	1,198
2027	401	840
2028	401	958
Thereafter	226	5,162
Total lease payments	**2,086**	**10,922**
Less: imputed interest	(377)	(1,651)
Total	**$ 1,709**	**$ 9,271**

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 $92.2 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2023 and $90.9 million in 2022.

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 coal 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 two 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 $4.9 million as of December 31, 2023, related to the twelve sites. We have paid remediation costs related to the twelve sites. We have recorded an estimated liability of $0.6 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 $5.4 million to $6.0 million as of December 31, 2023. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. It is anticipated that costs would be recovered in rates typical of historical Site Investigation and Remediation (SIR) rate recovery.

Manufactured gas plants

We have a program to investigate and perform necessary remediation and/or monitoring at our 39 sites where coal gas was manufactured in the past. The Company has entered into orders on consent with the NYSDEC for 37 sites and into a Brownfield Cleanup Program for 1 site. Those orders require us to investigate and, where necessary, remediate 38 of our 39 sites, with the 39th site the responsibility of another potentially responsible party (PRP). Six sites are included in the New York State Registry.

Our estimate for costs related to investigation, remediation and/or monitoring of the 38 sites ranges from $51.1 million to $123.8 million at December 31, 2023. 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, changes due to property use and changes to current laws and regulations.

The liability to investigate and perform remediation and/or monitoring, as necessary, at the known inactive coal gas manufacturing sites was $53.9 million at December 31, 2023 and $71.6 million at December 31, 2022. 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 coal 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 share of clean up expenses at nine manufactured gas plant sites. Based on current projections, FirstEnergy's share is estimated at approximately $7.6 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, 2023 and 2022, respectively, and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2023 and 2022, 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, 2023	Electricity	Natural Gas		2023	Electricity	Natural Gas
Regulatory assets	$ 16,807	$ 3,211	Electricity and natural gas purchased		$ 75,022	$ 5,618
Regulatory liabilities	$ —	$ —				
December 31, 2022				2022		
Regulatory assets	$ 6,893	$ 1,531	Electricity and natural gas purchased		$ (82,937)	$ (4,644)
Regulatory liabilities	$ —	$ —				

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

	Electricity Contracts	Natural Gas Contracts
Year to settle	Mwhs	Dths
As of December 31, 2023		
2024	3,064,100	2,630,000
2025	717,600	370,000
As of December 31, 2022		
2023	2,940,250	2,920,000
2024	877,800	330,000

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2023 and 2022, respectively, consisted of:

December 31, 2023	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 8,021	$ 2,285	$ 8,021	$ 2,285
Derivative liabilities	(8,021)	(2,285)	(23,551)	(6,774)
	—	—	(15,530)	(4,489)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	—	—
	—	—	—	—
Total derivatives before offset of cash collateral	—	—	(15,530)	(4,489)
Cash collateral receivable	—	—	15,530	4,489
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ —**	**$ —**

December 31, 2022	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 20,979	$ 4,611	$ 20,978	$ 4,611
Derivative liabilities	(20,979)	(4,611)	(28,251)	(5,762)
	—	—	(7,273)	(1,151)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(21)	—
	—	—	(21)	—
Total derivatives before offset of cash collateral	—	—	(7,294)	(1,151)
Cash collateral receivable	—	—	7,273	1,151
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (21)**	**$ —**

As of December 31, 2023 and 2022, 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, 2023 and 2022, 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)				
2023				
Interest rate contracts	$ —	Interest expense	$ (44)	$ 86,858
Commodity contracts: Other	—	Operations and maintenance	—	907,062
Foreign exchange contracts	—	Operations and maintenance	—	907,062
Total	**$ —**		**$ (44)**	
2022				
Interest rate contracts	$ —	Interest expense	$ (105)	$ 61,634
Commodity contracts: Other	1,207	Operations and maintenance	1,263	793,570
Foreign exchange contracts	—	Operations and maintenance	(27)	793,570
Total	**$ 1,207**		**$ 1,131**	

There is no gain (loss) amount in AOCI related to previously settled forward starting swaps and accumulated amortization as of December 31, 2023. There was a net loss of $0.05 million in AOCI related to previously settled forward starting swaps and accumulated amortization as of December 31, 2022, which was fully amortized during the year ended December 31, 2023.

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, 2023 is $20 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 $2,720 million and $2,056 million as of December 31, 2023 and 2022, 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, 2023 and 2022 consisted of:

Description	(Level 1)	(Level 2)	(Level 3)	Netting	Total
(Thousands)					
As of December 31, 2023					
Assets					
Non-current investments available for sale, primarily money market funds	$ 8,779	$ —	$ —	$ —	$ 8,779
Derivatives					
Commodity contracts:					
Electricity	10,267	—	—	(10,267)	—
Natural gas	39	—	—	(39)	—
Total	**$ 19,085**	**$ —**	**$ —**	**$ (10,306)**	**$ 8,779**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (27,074)	$ —	$ —	$ 27,074	$ —
Natural gas	(3,251)	—	—	3,251	—
Total	**$ (30,325)**	**$ —**	**$ —**	**$ 30,325**	**$ —**
As of December 31, 2022					
Assets					
Non-current investments available for sale, primarily money market funds	$ 8,262	$ —	$ —	$ —	$ 8,262
Derivatives					
Commodity contracts:					
Electricity	25,476	—	—	(25,476)	—
Natural gas	114	—	—	(114)	—
Total	**$ 33,852**	**$ —**	**$ —**	**$ (25,590)**	**$ 8,262**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (32,369)	$ —	$ —	$ 32,369	$ —
Natural gas	(1,644)	—	—	1,644	—
Foreign exchange contracts	—	(21)	—	—	(21)
Total	**$ (34,013)**	**$ (21)**	**$ —**	**$ 34,013**	**$ (21)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2023 and 2022. 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 may 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 fleet fuel program was terminated as of September 30, 2022. The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2023 and 2022 consisted of:

	(Level 3) Derivatives, Net	
Years Ended December 31,	**2023**	**2022**
(Thousands)		
Beginning balance	$ —	$ 56
Realized gains included in earnings	—	(1,263)
Unrealized gains included in other comprehensive income	—	1,207
Ending balance	**$ —**	**$ —**

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, 2023 and 2022, consisted of:

(Thousands)	Balance, December 31, 2021	Change 2022	Balance, December 31, 2022	Change 2023	Balance, December 31, 2023
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of income tax expense of $102 for 2022 and $9 for 2023	$ (889)	$ 286	$ (603)	$ 24	$ (579)
Unrealized gain (loss) on derivatives qualified as hedges:					
Unrealized gain during period on derivatives qualified as hedges, net of income tax expense of $205 for 2022 and $0 for 2023		1,002		—	
Reclassification adjustment for gain included in net income, net of income tax benefit of ($210) for 2022 and ($0) for 2023		(1,026)		—	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $18 for 2022 and income tax benefit of ($183) for 2023		87		227	
Net unrealized gain (loss) on derivatives qualified as hedges	(280)	63	(217)	227	10
Accumulated Other Comprehensive Loss	**$ (1,169)**	**$ 349**	**$ (820)**	**$ 251**	**$ (569)**

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. During 2022, the Company decided to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to the 401(k) Plan.

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 $16.7 million for both 2023 and 2022.

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 $2.4 million and $2.7 million at December 31, 2023 and 2022, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 1,136,121	$ 1,592,830	$ 95,760	$ 143,135
Service cost	3,695	10,986	332	795
Interest cost	56,209	51,367	4,632	3,598
Actuarial loss (gain)	57,264	(342,467)	6,238	(41,098)
Curtailments	—	(20,456)	—	—
Settlements	—	(67,875)	—	—
Benefits paid	(93,326)	(88,264)	(12,469)	(10,670)
Benefit obligation at December 31	**$ 1,159,963**	**$ 1,136,121**	**$ 94,493**	**$ 95,760**
Change in plan assets				
Fair value of plan assets at January 1	$ 1,115,006	$ 1,543,061	$ 29,337	$ 49,342
Actual return on plan assets	92,653	(271,916)	4,658	(10,010)
Employer & plan participants' contributions	—	—	—	675
Settlements	—	(67,875)	—	—
Benefits paid	(93,326)	(88,264)	(13,757)	(10,670)
Fair value of plan assets at December 31	**$ 1,114,333**	**$ 1,115,006**	**$ 20,238**	**$ 29,337**
Funded status	**$ (45,630)**	**$ (21,115)**	**$ (74,255)**	**$ (66,423)**

During 2023, the pension benefit obligation had an actuarial loss of $57.3 million. This loss was primarily driven by $53.4 million loss from decrease in discount rates. During 2023, the postretirement benefit obligation had an actuarial loss of $6.2 million. This loss was primarily driven by $3.3 million loss from decrease in discount rates.

During 2022, the pension benefit obligation had an actuarial gain of $342.5 million. This gain was primarily driven by $103.3 million gain from increase in discount rates. In 2022, the pension benefit obligation had a reduction of $67.9 million from settlements and $20.5 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. During 2022, the postretirement benefit obligations had an actuarial gain of $41.1million. This gain was primarily driven by $22.9 million gain from increase in discount rates.

Amounts recognized in the balance sheet as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Noncurrent liabilities	$ (45,630)	$ (21,115)	$ (74,255)	$ (66,423)

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,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Net loss (gain)	$ 99,656	$ 60,826	$ (37,088)	$ (46,370)
Prior service cost	$ —	$ —	$ —	$ —

Our accumulated benefit obligation for all qualified defined benefit pension plans was $1,146 million and $1,119 million as of December 31, 2023 and 2022, respectively. NYSEG's postretirement benefits were partially funded as of December 31, 2023 and 2022.

The projected benefit obligation exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2023 and 2022. The accumulated benefit obligation exceeded the fair value of pension plan assets as of December 31, 2023 and 2022. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2023 and 2022.

As of December 31,	**2023**	**2022**
(Thousands)		
Projected benefit obligation	$ 1,159,963	$ 1,136,121
Accumulated benefit obligation	$ 1,145,637	$ 1,119,298
Fair value of plan assets	$ 1,114,333	$ 1,115,006

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2023 and 2022.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2023 and 2022 consisted of:

Years Ended December 31,	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
(Thousands)				
Net periodic benefit cost				
Service cost	$ 3,695	$ 10,986	$ 332	$ 795
Interest cost	56,209	51,367	4,632	3,598
Expected return on plan assets	(75,845)	(78,148)	(1,165)	(1,584)
Amortization of prior service cost (credit)	—	124	—	—
Amortization of net loss (gain)	1,626	34,727	(6,537)	(2,260)
Curtailment charge	—	1,995	—	—
Settlement charge	—	3,634	—	—
Net periodic benefit cost	**$ (14,315)**	**$ 24,685**	**$ (2,738)**	**$ 549**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ 40,455	$ 7,598	$ 2,745	$ (29,505)
Amortization of net (loss) gain	(1,626)	(34,727)	6,537	2,260
Amortization of prior service (cost) credit	—	(124)	—	—
Effect of curtailments on prior service credit	—	(1,995)	—	—
Effect of curtailments on gain	—	(20,456)	—	—
Settlements	—	(3,634)	—	—
Total recognized in regulatory assets and regulatory liabilities	**$ 38,829**	**$ (53,338)**	**$ 9,282**	**$ (27,245)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ 24,514**	**$ (28,653)**	**$ 6,544**	**$ (26,696)**

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, 2023 and 2022 consisted of:

As of December 31,	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
Discount rate	4.65 %	5.17 %	4.65 %	5.10 %
Rate of compensation increase	2.50% Union	3.00% Union	N/A	N/A
Interest crediting rate	3.50 %	3.56 %	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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	2023	2022	2023	2022
Discount rate	5.17%	2.85% / 4.08%	5.10 %	2.61 %
Expected long-term return on plan assets	6.00%	6.00% / 5.50%	3.97 %	3.21 %
Rate of compensation increase	3.00% Union	Age-Related Rates / 3.00% Union	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.

Assumed health care cost trend rates to determine benefit obligations as of December 31, 2023 and 2022 consisted of:

As of December 31,	2023	2022
Health care cost trend rate (pre 65/post 65)	8.10% / 8.60%	6.00% / 6.50%
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	2031 / 2032	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 2024.

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)						
2024	$	100,108	$	9,856	$	—
2025	$	97,106	$	9,466	$	—
2026	$	96,495	$	9,019	$	—
2027	$	94,489	$	8,585	$	—
2028	$	92,680	$	8,211	$	—
2029-2033	$	425,504	$	34,394	$	—

***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 have diversified asset allocation policy that mitigates risk and volatility while meeting or exceeding our projected expected return to ensure that current and future benefit obligations are adequately funded. Further diversification and risk mitigation is achieved within each asset class by avoiding significant concentrations in certain markets, utilizing a combination or passive and active investment managers with unique skills and expertise, a 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 15%-70% for Return-Seeking assets and 30%-85% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international and emerging equity, 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, 2023, by asset category, consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2023				
Cash and cash equivalents	$ 33,606	$ 84	$ 33,522	$ —
U.S. government securities	168,562	168,562	—	—
Common stocks	16,699	16,699	—	—
Registered investment companies	53,384	53,384	—	—
Corporate bonds	437,407	—	437,407	—
Common collective trusts	144,801	—	144,801	—
Other, principally annuity, fixed income	23,503	—	23,503	—
	$ 877,962	**$ 238,729**	**$ 639,233**	**$ —**
Other investments measured at net asset value	236,371			
Total	**$ 1,114,333**			

The fair values of pension benefits plan assets as of December 31, 2022, by asset category, consisted of:

Notes to Financial Statements

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2022				
Cash and cash equivalents	$ 17,898	$ 33	$ 17,865	$ —
U.S. government securities	169,505	169,505	—	—
Common stocks	20,492	20,492	—	—
Registered investment companies	53,212	53,212	—	—
Corporate bonds	403,442	—	403,442	—
Preferred stocks	498	498	—	—
Common collective trusts	161,134	—	161,134	—
Other, principally annuity, fixed income	29,335	—	29,335	—
	$ 855,516	**$ 243,740**	**$ 611,776**	**$ —**
Other investments measured at net asset value	259,490			
Total	**$ 1,115,006**			

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, 2023 consisted of:

			Fair Value Measurements				
Asset Category		**Total**		**(Level 1)**		**(Level 2)**		**(Level 3)**
(Thousands)								
As of December 31, 2023								
Cash and cash equivalents	$	1,387	$	—	$	1,387	$	—
Registered investment companies		18,851		18,851		—		—
Total	**$**	**20,238**	**$**	**18,851**	**$**	**1,387**	**$**	**—**

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2022 consisted of:

				Fair Value Measurements				
Asset Category		**Total**		**(Level 1)**		**(Level 2)**		**(Level 3)**
(Thousands)								
As of December 31, 2022								
Cash and cash equivalents	$	689	$	—	$	689	$	—
Registered investment companies		28,648		28,648		—		—
Total	**$**	**29,337**	**$**	**28,648**	**$**	**689**	**$**	**—**

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.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2023 and 2022.

Note 16. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2023 and 2022, consisted of:

Years Ended December 31,	2023	2022
(Thousands)		
Carrying costs on regulatory assets	$ 22,756	$ 14,868
Allowance for funds used during construction	24,305	23,591
Miscellaneous	2,577	383
Total other income	**$ 49,638**	**$ 38,842**
Pension non-service components	$ 19,143	$ (12,012)
Miscellaneous	(5,515)	61
Total other (deductions) income, net	**$ 13,628**	**$ (11,951)**

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 $145.7 million for 2023 and $130.8 million for 2022. Cost for services includes amounts capitalized in utility plant, which was approximately $21.1 million in 2023 and $19.6 million in 2022. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by NYSEG to AGR and its subsidiaries were approximately $19.6 million for 2023 and $20.4 million for 2022. 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 $120.6 million at December 31, 2023 and $113.2 million at December 31, 2022 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $4.9 million at December 31, 2023 and $3.7 million at December 31, 2022 is from various companies. There were no notes receivable from affiliates at December 31, 2023 and 2022. 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 no outstanding receivable from New York TransCo as of December 31, 2023 and 2022.

Note 18. Subsequent Events

The company has performed a review of subsequent events through March 22, 2024, 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, 2023 and 2022

Rochester Gas and Electric Corporation

Index

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

Independent Auditors' Report

Stockholder 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, 2023 and 2022, 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, 2023 and 2022, 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 available to be 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, 2024

Rochester Gas and Electric Corporation
Statements of Income

Years Ended December 31,	2023	2022
(Thousands)		
Operating Revenues	**$ 1,221,747**	**$ 1,180,485**
Operating Expenses		
Electricity purchased	173,544	202,554
Natural gas purchased	122,212	173,509
Operations and maintenance	400,318	349,207
Depreciation and amortization	130,846	121,478
Taxes other than income taxes, net	156,091	149,796
Total Operating Expenses	**983,011**	**996,544**
Operating Income	**238,736**	**183,941**
Other income	19,711	18,388
Other deductions	(6,438)	(8,722)
Interest expense, net of capitalization	(54,207)	(42,641)
Income Before Tax	**197,802**	**150,966**
Income tax expense	43,605	28,395
Net Income	**$ 154,197**	**$ 122,571**

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Years Ended December 31,	2023	2022
(Thousands)		
Net Income	**$ 154,197**	**$ 122,571**
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of income tax	318	1,453
Unrealized gain during the period on derivatives qualifying as cash flow hedges, net of income tax	—	311
Reclassification to net income of gain on settled cash flow commodity hedges, net of income tax	—	(315)
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax	2,716	2,716
Other Comprehensive Income, Net of Tax	**3,034**	**4,165**
Comprehensive Income	**$ 157,231**	**$ 126,736**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2023	2022
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 197	$ 4
Accounts receivable and unbilled revenues, net	210,138	231,159
Accounts receivable from affiliates	2,858	3,633
Fuel and natural gas in storage	10,453	35,302
Materials and supplies	26,745	19,668
Broker margin accounts	6,985	16,542
Income tax receivable	825	—
Prepaid property taxes	43,637	41,531
Regulatory assets	105,460	57,485
Other current assets	13,853	11,009
Total Current Assets	**421,151**	**416,333**
Utility plant, at original cost	5,381,423	5,099,925
Less accumulated depreciation	(1,384,955)	(1,296,550)
Net Utility Plant in Service	**3,996,468**	**3,803,375**
Construction work in progress	409,669	346,560
Total Utility Plant	**4,406,137**	**4,149,935**
Operating lease right of use assets	1,372	525
Regulatory and Other Assets		
Regulatory assets	488,461	402,941
Other	42,749	47,910
Total Regulatory and Other Assets	**531,210**	**450,851**
Total Assets	**$ 5,359,870**	**$ 5,017,644**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2023	2022
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 17,100	$ 76,300
Accounts payable and accrued liabilities	202,636	258,994
Accounts payable to affiliates	58,427	54,091
Interest accrued	9,192	8,266
Taxes accrued	2,199	15,511
Operating lease liabilities	1,878	1,986
Environmental remediation costs	17,767	18,945
Regulatory liabilities	79,101	82,138
Other	73,025	65,804
Total Current Liabilities	**461,325**	**582,035**
Regulatory and Other Liabilities		
Regulatory liabilities	528,741	620,788
Other Non-current Liabilities		
Deferred income taxes	524,937	463,266
Nuclear plant obligations	138,182	131,336
Pension and other postretirement	98,117	91,103
Operating lease liabilities	1,274	100
Asset retirement obligations	2,206	2,312
Environmental remediation costs	62,834	83,043
Other	28,758	50,408
Total Regulatory and Other Liabilities	**1,385,049**	**1,442,356**
Non-current debt	1,738,065	1,489,902
Total Liabilities	**3,584,439**	**3,514,293**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2023 and 2022)	194,429	194,429
Additional paid-in capital	1,305,552	1,080,703
Retained earnings	420,631	376,434
Accumulated other comprehensive loss	(27,943)	(30,977)
Treasury stock, at cost (4,379,300 shares at December 31, 2023 and 2022)	(117,238)	(117,238)
Total Common Stock Equity	**1,775,431**	**1,503,351**
Total Liabilities and Equity	**$ 5,359,870**	**$ 5,017,644**

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Years Ended December 31,	2023	2022
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 154,197**	**$ 122,571**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	130,846	121,478
Regulatory assets/liabilities amortization	(43,156)	21,643
Regulatory assets/liabilities carrying cost	(1,170)	1,213
Amortization of debt issuance costs	1,630	(1,812)
Deferred taxes	49,844	30,669
Pension cost	(902)	9,037
Stock-based compensation	—	420
Accretion expenses	122	128
Gain from disposal of property	(47)	(69)
Other non-cash items	(5,930)	(9,788)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	21,796	(60,483)
Inventories	17,772	(24,196)
Accounts payable, to affiliates, and accrued liabilities	(54,094)	(28,936)
Taxes accrued	(14,137)	15,190
Other assets/liabilities	(14,328)	26,282
Regulatory assets/liabilities	(157,145)	(149,919)
Net Cash Provided by Operating Activities	**85,298**	**73,428**
Cash Flow From Investing Activities:		
Capital expenditures	(421,114)	(352,922)
Contributions in aid of construction	11,470	35,809
Proceeds from sale of property, plant and equipment	26,498	1,073
Net Cash Used in Investing Activities	**(383,146)**	**(316,040)**
Cash Flow From Financing Activities:		
Non-current debt issuance	246,084	125,413
Repayments of finance leases	(3,843)	(5,600)
Notes payable to affiliates	(59,200)	22,800
Capital contributions	225,000	225,000
Dividends paid	(110,000)	(125,000)
Net Cash Provided by Financing Activities	**298,041**	**242,613**
Net Increase in Cash and Cash Equivalents	**193**	**1**
Cash and Cash Equivalents, Beginning of Period	**4**	**3**
Cash and Cash Equivalents, End of Period	**$ 197**	**$ 4**

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, 2021	**38,885,813**	**$**	**194,429**	**$**	**855,312**	**$**	**378,863**	**$**	**(35,142)**	**$**	**(117,238)**	**$**	**1,276,224**
Net income	—		—		—		122,571		—		—		122,571
Other comprehensive income, net of tax	—		—		—		—		4,165		—		4,165
Comprehensive income													126,736
Stock-based compensation	—		—		391		—		—		—		391
Common stock dividends	—		—		—		(125,000)		—		—		(125,000)
Capital contributions	—		—		225,000		—		—		—		225,000
Balance, December 31, 2022	**38,885,813**	**$**	**194,429**	**$**	**1,080,703**	**$**	**376,434**	**$**	**(30,977)**	**$**	**(117,238)**	**$**	**1,503,351**
Net income	—		—		—		154,197		—		—		154,197
Other comprehensive income, net of tax	—		—		—		—		3,034		—		3,034
Comprehensive income													157,231
Stock-based compensation	—		—		(151)		—		—		—		(151)
Common stock dividends	—		—		—		(110,000)		—		—		(110,000)
Capital contributions	—		—		225,000		—		—		—		225,000
Balance, December 31, 2023	**38,885,813**	**$**	**194,429**	**$**	**1,305,552**	**$**	**420,631**	**$**	**(27,943)**	**$**	**(117,238)**	**$**	**1,775,431**

(*) 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 (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 391,200 electricity and 323,800 natural gas customers as of December 31, 2023, 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 81.6% 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 primarily 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 2.4% of average depreciable property for 2023 and 2.3% for 2022. 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 $178.0 million as of December 31, 2023 and $167.0 million as of December 31, 2022. Depreciation expense was $123.1 million in 2023 and $114.8 million in 2022. Amortization of capitalized software was $7.7 million in 2023 and $6.6 million in 2022.

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)**	**2023**	**2022**
(Thousands)			
Electric	2-90	$ 3,601,110	$ 3,382,030
Natural Gas	7-80	1,229,480	1,179,527
Common	3-60	550,833	538,368
Utility plant at original cost		**5,381,423**	**5,099,925**
Less accumulated depreciation		(1,384,955)	(1,296,550)
Net Utility Plant in Service		**3,996,468**	**3,803,375**
Construction work in progress		409,669	346,560
Total Utility Plant		**$ 4,406,137**	**$ 4,149,935**

***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. If the amounts in OCI are probable of recovery in the ratemaking process, then the OCI is reclassified as a regulatory asset or liability. 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.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2023		2022
(Thousands)				
Cash paid (refunded) during the years ended December 31:				
Interest, net of amounts capitalized	$	49,808	$	46,076
Income taxes paid (refunded), net	$	8,421	$	(18,908)

Of the income taxes paid (refunded), substantially all was paid to (refunded by) AGR under the tax sharing agreement. Interest capitalized was $14.3 million in 2023 and $9.7 million in 2022. Accrued liabilities for utility plant additions were $65.4 million as of December 31, 2023 and $41.0 million as of December 31, 2022.

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 $64.8 million for 2023 and $69.8 million for 2022, and are shown net of an allowance for credit losses at December 31 of $44.5 million for 2023 and $37.2 million for 2022. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $41.1 million in 2023, including $17.6 million of arrears forgiveness balances. Credit loss expense was $34.9 million in 2022, including $31.2 million of arrears forgiveness balances. Arrears forgiveness balances will be recovered through a tariff over a five year period that began August 1, 2022 for Phase 1 and a three and a half year-period that began March 1, 2023 for Phase 2.

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. We 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 $10.9 million in 2023 and $9.2 million in 2022. DPA receivable balances at December 31 were $23.9 million in 2023 and $19.1 million in 2022.

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.

The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2023 and 2022 consisted of:

(Thousands)	Government grants	Total
As of December 31, 2021	**$ 17,852**	**$ 17,852**
Disposals	—	—
Recognized in income	(400)	(400)
As of December 31, 2022	**17,452**	**17,452**
Disposals	—	—
Recognized in income	(400)	(400)
As of December 31, 2023	**$ 17,052**	**$ 17,052**

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the government. We believe we are in compliance with each grant's terms and conditions as of December 31, 2023 and 2022.

Deferred income: Apart from government grants, we occasionally receive payments from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such payments 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. 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, 2023 and 2022.

Years Ended December 31,		2023		2022
(Thousands)				
ARO, beginning of year	$	2,312	$	2,430
Liabilities settled during the year		(229)		(246)
Accretion expense		123		128
ARO, end of year	**$**	**2,206**	**$**	**2,312**

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 2057.

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. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Prior service cost changes resulting from union bargaining agreements are amortized on a straight-line basis over the period from first recognition to the end of the bargaining agreement. 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**:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax (“CAMT”) of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The CAMT and other various applicable provisions of the IRA are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year, as well as on anticipated guidance from the U.S. Department of Treasury.

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, 2023 is $0.8 million. The aggregate amount of the related party income tax payable balance due to AGR at December 31, 2022 is $15.4 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 regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit 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, 2023 and 2022.

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. We consider the effect of the alternative minimum tax system in determining the need for a valuation allowance for deferred taxes. 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.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2023 that are expected to have a material impact on RG&E’s financial statements.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on RG&E's financial statements.

(a) Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance to enhance income tax disclosures. The two primary enhancements relate to disaggregation of the annual disclosures for the effective tax rate reconciliation and income taxes paid. For the rate reconciliation, it requires additional disaggregation of information in a tabular format using both percentages and amounts broken out into specific categories (e.g., state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, and changes in unrecognized tax benefits). For income taxes paid, it requires disaggregation by jurisdiction (e.g., federal, state and foreign). We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows. We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

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.

Union collective bargaining agreements: Approximately 47% 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 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.

2020 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, 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 $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	$—	—%	$—	—%	$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.

The Proposal provides that with few exceptions, the provisions for electric and gas service under the Proposal for Rate Year 3 (the twelve-month period ending April 30, 2026) shall continue unless and until such provisions and base delivery rates for electric or gas service are changed by subsequent order of the New York Public Service Commission. Thus, from May 1, 2023, until such time as new rates are approved by the Commission, the current rates and terms for Rate Year 3 of the prior Proposal remain in effect.

2023 RG&E Rate Plan

On May 26, 2022, RG&E made an initial filing to the NYPSC requesting increases to the delivery rates for its electric business of 19.0% and for its gas business of 20.9%. This initial filing started a lengthy process guided by NYPSC regulations. The Department of Public Service Staff and other parties to the rate cases submitted testimony on September 26, 2022.

On October 18, 2022, the Companies submitted rebuttal testimony responding to testimony of Department of Public Service Staff and other parties to the proceedings. On October 19, 2022, the Companies filed a notice of impending settlement negotiations. A Joint Proposal for a three year rate plan term was filed on June 14, 2023. The NYPSC issued an Order on October 12, 2023 approving the Joint Proposal in its entirety with one modification to acknowledge that the “make whole” period would be effective from May 1, 2023 through November 1, 2023, rather than October 1, 2023, as originally proposed in the Joint Proposal. The effective date of new tariffs was November 1, 2023 with make-whole back to May 1, 2023. The Joint Proposal bases delivery revenues on an 9.20% 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 eight parties, and includes levelized delivery rate increases as summarized below:

	May 1, 2023		**May 1, 2024**		**May 1, 2025**	
	Rate Increase (Millions)	**Delivery Rate Increase* %**	**Rate Increase (Millions)**	**Delivery Rate Increase* %**	**Rate Increase (Millions)**	**Delivery Rate Increase* %**
Electric	$51.0	11.0%	$56.6	11.0%	$65.3	11.0%
Gas	$18.2	10.2%	$20.1	10.2%	$22.4	10.2%

* Based on “net base delivery” revenues, which consist of gross base delivery revenue plus Bill Issuance Payment Process (BIPP), plus Gross Revenue Tax (GRT).

The approved Joint Proposal also reflects increased energy efficiency programs and distribution vegetation management, along with investments in aging infrastructure, resiliency, continued implementation of Advanced Metering Infrastructure (AMI), and increases in the Company’s workforce. The approved Joint Proposal reflects the continued recovery of deferred RG&E Electric storm costs and continued reserve accounting for qualifying Major Storms ($4.5 million in Rate Year 1, $6.0M in Rate Year 2 and $7.6M in Rate Year 3). Incremental maintenance costs incurred to restore service in will be chargeable to the Major Storm Reserve provided they meet certain thresholds for each storm event.

The approved Joint Proposal continued the 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 maintains 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, with increases to potential negative revenue adjustments. The approved Joint Proposal continues bill reduction and arrears forgiveness Low Income Programs. Certain 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, 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) costs associated with the implementation of any Commission-ordered EV program which are not covered by any other cost recovery mechanism; and (6) Covid-related uncollectibles (Rate Years 1 and 2 only).

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; Low Income Programs, and Covid-related Uncollectible Expense. The Proposal also includes downward-only Net Plant AMI and Resiliency Program 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 the Company continue the electric and gas revenue decoupling mechanisms (RDM) on a total revenue per class basis.

The Proposal provides that with few exceptions, the provisions for electric and gas service under the Proposal for Rate Year 3 (the twelve-month period ending April 30, 2026) shall continue unless and until such provisions and base delivery rates for electric or gas service are changed by subsequent order of the New York Public Service Commission. Thus, from May 1, 2023, until such time as new rates are approved by the Commission, the current rates and terms for Rate Year 3 of the prior Proposal remain in effect.

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 was 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 (DER), such as micro grids, on-site power supplies and storage.

The NYPSC issued a 2015 order in Track 1, which acknowledged the utilities' role as a Distribution System Platform provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) followed by bi-annual updates. The next scheduled DSIP update is June 30, 2025.

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. EAMs were approved by the Commission on November 19, 2020 in its Order approving the companies' 2020 Rate Plan. Modifications to EAMs were approved by the Commission on October 12, 2023 in its Order approving the companies' 2023 Rate Plan.

In 2017, the NYPSC approved a transition from traditional Net Energy Metering (NEM) towards a more values-based approach (Value Stack) for compensating DER. Since that time, the Commission has issued a number of orders on additional Value of Distributed Energy Resources matters. Most recently, the NYPSC Staff issued a proposal on Community Distributed Generation (CDG) Billing and Crediting Performance Metrics and Negative Revenue Adjustments (NRA). The NYPSC Staff recommends six CDG performance metrics with associated NRAs that would incent improvements to the CDG billing processes. At this time, the outcome of this proceeding is unknown.

Other REV-related orders pertaining to electric vehicles (EV), an Integrated Energy Data Resource (IEDR) platform and energy storage are summarized below.

- The NYPSC issued an Order on April 20, 2023 instituting a proceeding to advance infrastructure for medium and heavy-duty vehicles. The Joint Utilities filed an implementation plan with the NYPSC for the medium and heavy-duty pilot program. The Joint Utilities are awaiting the NYPSC's approval of the implementation plan.

- On February 11, 2021, the NYPSC issued an Order to implement an Integrated Energy Data Resource platform, where NYSERDA was designated as the Program Sponsor of the platform. 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 January 19, 2024, the NYPSC issued an Order approving Phase 2 budget, with costs up to the combined cost cap deferred for future recovery in the same manner as Phase 1.

- An order 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 EV charging stations.

- On December 13, 2018, the NYPSC issued an Order for utilities to file implementation plans detailing a competitive procurement process and cost recovery for deploying qualified storage systems. NYSEG and RG&E have tariffs in effect to collect costs for the procurement of qualified energy storage assets.

Customer Arrearages Reduction Order

On June 16, 2022, the NYPSC issued an order (Phase 1) authorizing an arrears reduction program targeting low-income customers to provide COVID-19-related relief through a one-time bill credit to eliminate accrued arrears through May 1, 2022. A portion of the targeted arrearages will be funded via direct contributions from the State of New York, and the remainder to be received via a surcharge to all customers. The surcharge recovery is over five years for RG&E beginning on August 1, 2022.

On January 19, 2023, the NYPSC issued a subsequent order (Phase 2) providing bill relief for customers who did not receive a credit as part of the Phase 1 Program approved in 2022 (Low Income Program participants). Qualifying residential and small business customers are eligible to have any past-due balance from bills for service through May 1, 2022, reduced through a one time bill credit, up to a maximum credit below:

Residential	Total Forecast Residential Credits (Millions)	Small Business	Total Forecast Small Business Credits (Millions)
Up to $1,500	$15.2	Up to $1,500	$0.6

The New York State Budget for 2023-2024 included an appropriation of $200 million designated to provide prompt utility bill relief. On February 15, 2024, the NYPSC issued an order authorizing and directing utilities, including RG&E, to provide one-time bill credits to customers to achieve the stated purpose of the budget appropriation. The February 15, 2024 NYPSC Order provides $7.2 million and $3.7 million, for RG&E Electric and Gas customers, respectively, to be distributed in the form of one-time credits to customers as shown below:

Service	Number of Customers	RG&E Allocation (Millions)	Estimated Credit (per customer)
Electric	390,454	$7.209	$18.46
Gas	322,924	$3.663	$11.34

Community Leadership and Climate Protection Act Transmission

Pursuant to the Community Leadership and Climate Protection Act of 2019 (CLCPA) and Accelerated Renewable Energy Growth and Community Benefit Act of 2020, the Commission has issued orders addressing investment in transmission by RG&E to support the state achieving the CLCPA's goal of 70% renewable energy by 2030. On February 16, 2023, the Commission issued an Order approving the investment of approximately $157 Million by RG&E through 2030 in CLCPA "Phase 2" transmission projects. Phase 2 transmission projects are upgrades to the RG&E local transmission system that are being developed primarily to allow for the interconnection and delivery of renewable energy in the Southern Tier, an area that the Commission has designated as an "Area of Concern" for renewable energy development because there is substantial renewable energy development interest but inadequate transmission. Unlike other transmission owned by RG&E, the cost of CLCPA Phase 2 transmission will be recovered pursuant to a formula rate under the jurisdiction of the Federal Energy Regulatory Commission (FERC) so that costs can be allocated statewide. RG&E and other transmission-owning utilities in New York negotiated a Cost Sharing and Recovery Agreement (CSRA), which was approved by the Commission on May 12, 2022, and by FERC on August 22, 2022. Under the terms of the CSRA the cost of CLCPA Phase 2 transmission projects approved by the Commission will be recovered through the New York Independent System Operator tariff, with ROE and capital structure determined by the Commission, subject to an ROE ceiling set by FERC.

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 $138.5 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 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 October 12, 2023, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at RG&E effective May 1, 2023. 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-three years. A majority of the other items related to RG&E will be amortized over a three-year period. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, net amortization revenue for RG&E is approximately $62.2 million for the year ended December 31, 2023.

Regulatory assets at December 31, 2023 and 2022 consisted of:

December 31,		2023		2022
(Thousands)				
Asset retirement obligation	$	3,207	$	3,199
COVID-19 late payment surcharge		8,128		2,444
Decommissioning		274		784
Deferred meter replacement costs		10,803		9,186
Delivery rate shaping		16,594		—
Environmental remediation costs		66,671		72,896
Federal tax depreciation normalization adjustment		42,154		43,566
Hedge losses		13,991		4,480
Low income program		10,684		15,960
Low income arrears forgiveness		31,238		16,926
Make-whole provision		29,566		—
Pension and other postretirement benefits		22,288		13,234
Pension and other postretirement benefits cost deferrals		9,286		13,050
Post term amortization		781		2,109
Rate adjustment mechanism		7,769		7,996
REV demand response		—		1,003
Revenue decoupling mechanism		15,503		4,358
Storm costs		52,413		65,240
Unamortized losses on reacquired debt		3,676		4,120
Uncollectible reserve		41,986		—
Unfunded future income taxes		157,192		150,465
Value of Distributed Energy Resources (VDER) Program		16,730		10,991
Other		32,987		18,419
Total regulatory assets		**593,921**		**460,426**
Less: current portion		105,460		57,485
Total non-current regulatory assets	**$**	**488,461**	**$**	**402,941**

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 late payment surcharge represents deferred lost late payment revenue in the state of New York based on the order issued by PSC on June 17, 2022, approving deferral and surcharge/sur-credit mechanism to recover/return deferred balances starting July 1, 2022.

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

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

Delivery rate shaping adjusts the New York delivery rate increases across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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 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.

Federal tax depreciation normalization adjustment represents the revenue requirement impact of the difference in the deferred income tax expense required to be recorded under the IRS normalization rules and the amount of deferred income tax expense that was included in cost of service for rate years covering 2011 forward. The recovery period is being amortized over a thirty-two year period starting in 2023.

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.

Low income arrears forgiveness program represents deferred bill credits in the State of New York based on the order issued by PSC on June 16, 2022, approving deferral of bill credits for low-income customers (Phase 1), and additional deferred bill credits for other residential and small commercial customers who did not qualify for Phase 1 based on the order issued by PSC on January 19, 2023 (Phase 2). The Phase 1 regulatory asset will be recovered from all customers over five years through a surcharge that began August 1, 2022. The Phase 2 regulatory asset will be recovered from all customers over three and a half years through a surcharge that began March 1, 2023.

Make-whole provision represents the regulatory asset to recover revenues that would have been received by RGE had Rate Year 1 rates approved in the 22-E-0317 et al. joint proposal gone into effect on the effective date of May 1, 2023. The balance is being recovered through a separately stated make-whole rate, effective November 1, 2022, over 6-30 months.

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. A portion of this balance is amortized through current rates, the remaining portion 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 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.

Uncollectible reserve includes the anticipated future rate recovery of costs that are recorded as uncollectible since those will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future uncollectible expense, it does not accrue carrying costs and is not included within rate base. It also includes the variance between actual uncollectible expense and uncollectible expense included in rates that is eligible for future recovery in customer rates. The amortization period will be established in future proceedings.

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 represent a mechanism to compensate for energy created by distributed energy resources, like solar.

Other includes items such as earnings sharing mechanism, methane detection program and electric vehicle deferral.

Regulatory liabilities at December 31, 2023 and 2022 consisted of:

December 31,		2023		2022
(Thousands)				
Accrued removal obligations	$	173,561	$	190,158
Asset retirement obligation		4,955		4,851
Carrying costs on deferred income tax bonus depreciation		3,043		8,765
Debt rate reconciliations		—		5,451
Deferred property taxes		15,276		13,645
Deferred transmission congestion contracts		26,489		30,975
Delivery rate shaping		—		11,506
Earnings sharing		4,563		7,131
Economic development		4,520		13,625
Electric supply reconciliation		4,247		3,627
Energy efficiency programs		4,196		12,002
Environmental remediation costs		—		7,509
Gas supply charge		1,092		149
Merger capital expense		—		2,778
Mixed use 263(a)		1,554		2,719
NEIL (Nuclear Electric Insurance Limited) credits		4,817		12,014
Net plant reconciliation		12,158		10,893
Pension and other postretirement benefits		17,723		20,058
Pension and other postretirement benefits cost deferrals		3,501		2,234
Positive benefit adjustment		8,704		15,231
Service quality performance mechanism		15,692		—
Tax Act – remeasurement		252,887		259,878
Theoretical reserve flow through impact		1,674		2,930
Unfunded future income taxes		3,260		3,124
Other		43,930		61,673
Total regulatory liabilities		**607,842**		**702,926**
Less: current portion		79,101		82,138
Total non-current regulatory liabilities	**$**	**528,741**	**$**	**620,788**

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.

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases

Deferred transmission congestion contracts represent the deferral of the right to collect day-ahead market congestions rents going forward in time. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

Earning sharing provisions represents the annual earnings over the earning 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.

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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.

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.

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of AVANGRID (formerly Energy East Corporation). A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

Service Quality Performance Mechanism represents positive or negative revenue adjustments from metric standards either missed or achieved. The standards are established in the rate case. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases

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.

Theoretical reserve flow through impact represents the difference 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. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases.

Other includes items such as Clean Energy Fund (CEF), NEIL credit deferral, manhole maintenance 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 $0.6 million at December 31, 2023, and $0.6 million at December 31, 2022, and are presented in "Other current liabilities" on our balance sheets. We recognized $1.0 million as revenue in 2023 and $0.9 million in 2022.

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, 2023 and 2022 are as follows:

Years Ended December 31,	**2023**	**2022**
(Thousands)		
Regulated operations – electricity	$ 835,405	$ 770,244
Regulated operations – natural gas	345,250	373,666
Other (a)	14,945	24,386
Revenue from contracts with customers	**1,195,600**	**1,168,296**
Leasing revenue	68	69
Alternative revenue programs	20,670	8,556
Other revenue	5,409	3,564
Total operating revenues	**$ 1,221,747**	**$ 1,180,485**

(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, 2023 and 2022 consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Current				
Federal	$	(5,892)	$	(885)
State		(347)		(1,389)
Current taxes charged to benefit		**(6,239)**		**(2,274)**
Deferred				
Federal		37,738		20,310
State		12,106		10,359
Deferred taxes charged to expense		**49,844**		**30,669**
Total Income Tax Expense	**$**	**43,605**	**$**	**28,395**

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, 2023 and 2022, respectively, consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Tax expense at federal statutory rate	$	41,538	$	31,718
Equity AFUDC tax impacts not normalized		(1,916)		(2,305)
Excess ADIT amortization		(5,557)		(9,829)
Excess ADIT write-off		—		1,693
State tax expense, net of federal benefit		9,290		7,086
Other, net		250		32
Total Income Tax Expense	**$**	**43,605**	**$**	**28,395**

Income tax expense for the year ended December 31, 2023 was $2.1 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state tax expense, partially offset by excess Accumulated Deferred Income Tax (ADIT) amortization and Equity AFUDC tax effects. This resulted in an effective tax rate of 22.0%. Income tax expense for the year ended December 31, 2022, was $3.3 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 and Excess ADIT write-off. This resulted in an effective tax rate of 18.8%.

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, 2023 and 2022 consisted of:

December 31,		2023		2022
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	614,015	$	565,835
Unfunded future income taxes		39,394		37,493
Storms		13,701		18,775
Regulatory liability due to "Tax Cuts and Jobs Act"		(66,104)		(67,919)
Pension and other postretirement benefits		(24,957)		(25,634)
Derivative assets		(9,740)		(10,701)
Environmental		(3,641)		(9,566)
Federal and state net operating loss		(67,630)		(26,473)
Other		29,899		(18,544)
Total Non-current Deferred Income Tax Liabilities	**$**	**524,937**	**$**	**463,266**
Deferred tax assets	$	172,072	$	158,837
Deferred tax liabilities		697,009		622,103
Net Accumulated Deferred Income Tax Liabilities	**$**	**524,937**	**$**	**463,266**

RG&E has gross federal net operating losses of $214.5 million and gross New York state net operating losses of $439.9 million for the year ended December 31, 2023. RG&E has gross federal net operating losses of $71.7 million and gross New York state net operating losses of $222.3 million for the year ended December 31, 2022.

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, 2023 and 2022 consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Beginning Balance	$	48,813	$	49,100
Reduction for tax positions related to prior years		(287)		(287)
Ending Balance	**$**	**48,526**	**$**	**48,813**

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, 2023 and December 31, 2022.

Note 6. Long-term Debt

Long-term debt as of December 31, 2023 and 2022 consisted of:

As of December 31,		2023		2022	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2025-2053	$ 1,660,500	1.85%-8.00%	$ 1,410,500	1.85%-8.00%
Unsecured pollution control notes - fixed	2025	91,900	3.00%	91,900	3.00%
Unamortized debt issuance cost and discount		(14,335)		(12,498)	
Total Debt		**1,738,065**		**1,489,902**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 1,738,065**		**$ 1,489,902**	

(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 December 15, 2022, RG&E issued $125 million aggregate principal amount of first mortgage bonds maturing in 2052 at an interest rate of 4.86%.

On December 13, 2023, RG&E issued a total $250 million aggregate principal amount of green private bonds, consisting of $100 million maturing in 2028 at an interest rate of 5.63%, $25 million maturing in 2034 at an interest rate of 5.89%, $50 million maturing in 2036 at an interest rate of 5.99% and $75 million maturing in 2053 at an interest rate of 6.22%.

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

2024	2025	2026	2027	2028	Total
(Thousands)					
$ —	$ 152,400	$ —	$ 450,000	$ —	$ 602,400

We have no financial debt covenant requirements related to our long-term debt at December 31, 2023 and 2022.

Note 7. Bank Loans and Other Borrowings

RG&E had $17.1 million of notes payable outstanding as of December 31, 2023 and $76.3 million of notes payable outstanding as of December 31, 2022. 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 no debt outstanding under this agreement as of December 31, 2023 and 2022.

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 $17.1 million outstanding under this agreement as of December 31, 2023 and $76.3 million as of December 31, 2022.

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, 2023 and 2022.

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 0.50 to 1.00 at December 31, 2023. We are not in default as of December 31, 2023.

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 13 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,	2023	2022
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 4,208	$ 4,679
Interest on lease liabilities	1,006	1,101
Total finance lease cost	5,214	5,780
Operating lease cost	516	510
Short-term lease cost	822	588
Variable lease cost	367	532
Intercompany	72	71
Total lease cost	**$ 6,991**	**$ 7,481**

Balance sheet and other information for the years ended December 31, 2023 and 2022 was as follows:

As of December 31,	2023	2022
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 1,372	$ 525
Operating lease liabilities, current	1,878	1,986
Operating lease liabilities, long-term	1,274	100
Total operating lease liabilities	$ 3,152	$ 2,086
Finance Leases		
Other assets	$ 40,868	$ 45,076
Other current liabilities	21,624	3,969
Other non-current liabilities	18,353	39,851
Total finance lease liabilities	$ 39,977	$ 43,820
Weighted-average Remaining Lease Term (years):		
Finance leases	6.69	7.33
Operating leases	4.64	1.31
Weighted-average Discount Rate:		
Finance leases	2.26 %	2.42 %
Operating leases	4.24 %	3.15 %

Supplemental cash flows information related to leases was as follows:

For the Years Ended December 31,		2023		2022
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	236	$	295
Operating cash flows from finance leases	$	970	$	1,136
Financing cash flows from finance leases	$	3,843	$	5,600
Right-of-use assets obtained in exchange for lease obligations:				
Finance leases	$	—	$	1,718
Operating leases	$	1,402	$	8

As of December 31, 2023, maturities of lease liabilities were as follows:

		Finance Leases		Operating Leases
(Thousands)				
Years ending December 31,				
2025	$	22,352	$	1,904
2026		1,719		172
2027		1,744		171
2028		1,773		169
2029		1,803		55
Thereafter		14,315		997
Total lease payments		**43,706**		**3,468**
Less: imputed interest		(3,729)		(316)
Total	**$**	**39,977**	**$**	**3,152**

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 $56.4 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2023 and $53.5 million in 2022.

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 coal 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 $0.1 million at December 31, 2023, related to eight sites. We have recorded an estimated liability of $5.2 million related to another six sites where we believe it is probable that we will incur remediation costs and/or monitoring costs. 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 $4.9 million to $5.6 million as of December 31, 2023. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. It is anticipated that costs would be recovered in rates, typical of historical Site Investigation and Remediation rate recovery.

Manufactured gas plants

We have a program to investigate and perform necessary remediation and/or monitoring at our eleven sites where coal gas was manufactured in the past. The Company has advanced work under an existing order on consent with the NYSDEC at three of the sites, with a fourth site with the potential to be added to the order in 2024. The order requires us to investigate and, where necessary, remediate and/or monitor our eleven sites. Seven sites were advanced under NYS's former Voluntary Cleanup Program (VCP) that was discontinued in 2018. Work at those sites continues, as applicable in accordance with Site Management Plans (SMPs) and institutional controls.

Our estimate for costs related to investigation and remediation and/or monitoring of the eleven sites ranges from $70.9 million to $93.6 million at December 31, 2023. 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, changes due to property use and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive coal gas manufacturing sites was $75.3 million at December 31, 2023, and $96.4 million at December 31, 2022. 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 2057.

First Energy

RG&E sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at two former manufactured coal gas sites, which are included in the discussion above. In 2008, the District Court issued a decision and order in RG&E's favor requiring FirstEnergy to pay RG&E for past and future clean-up costs at the two manufactured gas plant sites. As such, FirstEnergy is liable for a share of clean up expenses at the two sites. Based on current projections, FirstEnergy’s share is estimated at approximately $5.6 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 RG&E ratepayers.

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, 2023 and 2022 and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2023 and 2022 are as follows:

(Thousands)	Loss (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, 2023	**Electricity**	**Natural Gas**	**2023**	**Electricity**	**Natural Gas**
Regulatory assets	$ 5,212	$ 8,779	Electricity and natural gas purchased	$ 26,911	$ 9,139
Regulatory liabilities	$ —	$ —			
December 31, 2022			**2022**		
Regulatory assets	$ 2,231	$ 2,249	Electricity and natural gas purchased	$ (43,812)	$ (11,653)
Regulatory liabilities	$ —	$ —			

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

	Electricity Contracts	Natural Gas Contracts
Years to settle	**Mwhs**	**Dths**
As of December 31, 2023		
2024	1,500,775	6,630,000
2025	321,000	1,030,000
As of December 31, 2022		
2023	1,473,575	5,540,000
2024	449,000	840,000

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2023 and 2022, respectively, consisted of:

December 31, 2023	Derivative Assets Current	Derivative Assets Non-current	Derivative Liabilities Current	Derivative Liabilities Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 4,130	$ 1,057	$ 4,130	$ 1,057
Derivative liabilities	(4,130)	(1,057)	(15,987)	(3,191)
	—	—	(11,857)	(2,134)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	—	—
	—	—	—	—
Total derivatives before offset of cash collateral	—	—	(11,857)	(2,134)
Cash collateral receivable	—	—	11,857	2,134
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ —**	**$ —**

December 31, 2022	Derivative Assets Current	Derivative Assets Non-current	Derivative Liabilities Current	Derivative Liabilities Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 9,245	$ 2,488	$ 9,245	$ 2,488
Derivative liabilities	(9,245)	(2,488)	(12,593)	(3,620)
	—	—	(3,348)	(1,132)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(21)	—
	—	—	(21)	—
Total derivatives before offset of cash collateral	—	—	(3,369)	(1,132)
Cash collateral receivable	—	—	3,348	1,132
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (21)**	**$ —**

As of both December 31, 2023 and 2022, 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, 2023 and 2022, respectively, consisted of:

Years Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of Loss Reclassified From Accumulated OCI into Income	Loss (Gain) Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2023				
Interest rate contracts	$ —	Interest expense	$ (3,678)	$ 54,207
Commodity contracts: Other	—	Other operating expenses	—	400,318
Foreign exchange contracts	—	Other operating expenses	—	400,318
Total	**$ —**		**$ (3,678)**	
2022				
Interest rate contracts	$ —	Interest expense	$ (3,678)	$ 42,641
Commodity contracts: Other	420	Other operating expenses	448	349,207
Foreign exchange contracts	—	Other operating expenses	(22)	349,207
Total	**$ 420**		**$ (3,252)**	

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization at December 31, 2023 is a net loss of $37.3 million as compared to $40.9 million at December 31, 2022. For the year ended December 31, 2023, 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 2024.

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, 2023 is $14.0 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 $1,703 million as of December 31, 2023 and $1,401 million as of December 31, 2022. 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 fair value hierarchy for the fair value of debt is considered as Level 2.

The financial instruments measured at fair value as of December 31, 2023 and 2022 consisted of:

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2023					
Assets					
Derivatives					
Commodity contracts:					
Electricity	$ 5,091	$ —	$ —	$ (5,091)	$ —
Natural Gas	96	—	—	(96)	—
Total	**$ 5,187**	**$ —**	**$ —**	**$ (5,187)**	**$ —**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (10,303)	$ —	$ —	$ 10,303	$ —
Natural gas	(8,875)	—	—	8,875	—
Total	**$ (19,178)**	**$ —**	**$ —**	**$ 19,178**	**$ —**

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2022					
Assets					
Derivatives					
Commodity contracts:					
Electricity	$ 11,249	$ —	$ —	$ (11,249)	$ —
Natural Gas	484	—	—	(484)	—
Total	**$ 11,733**	**$ —**	**$ —**	**$ (11,733)**	**$ —**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (13,480)	$ —	$ —	$ 13,480	$ —
Natural gas	(2,733)	—	—	2,733	—
Foreign exchange contracts	—	(21)	—	—	(21)
Total	**$ (16,213)**	**$ (21)**	**$ —**	**$ 16,213**	**$ (21)**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2023. 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.

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 may 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, 2023 and 2022 consisted of:

	Derivatives, Net	
Years Ended December 31,	**2023**	**2022**
(Thousands)		
Beginning balance	$ —	$ 28
Realized gains included in earnings	—	(448)
Unrealized gains included in other comprehensive income	—	420
Ending balance	**$ —**	**$ —**

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, 2023 and 2022, consisted of:

(Thousands)	Balance December 31, 2021	2022 Change	Balance December 31, 2022	2023 Change	Balance December 31, 2023
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of tax expense of $514 for 2022 and $113 for 2023	$ (2,191)	$ 1,453	$ (738)	$ 318	$ (420)
Unrealized gain (loss) on derivatives qualified as hedges:					
Unrealized gain during period on derivatives qualified as hedges, net of income tax expense of $109 for 2022 and $0 for 2023		311		—	
Reclassification adjustment for gain included in net income, net of income tax benefit of $111 for 2022 and $0 for 2023		(315)		—	
Reclassification adjustment for loss on settled cash flow treasury hedges included in net income, net of income tax expense of $962 for 2022 and $962 for 2023		2,716		2,716	
Net unrealized gain on derivatives qualified as hedges	(32,951)	2,712	(30,239)	2,716	(27,523)
Accumulated Other Comprehensive Loss	**$ (35,142)**	**$ 4,165**	**$ (30,977)**	**$ 3,034**	**$ (27,943)**

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. During 2022, the Company decided to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to the 401(k) Plan.

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 $9.1 million in 2023 and $7.2 million in 2022.

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 $8.0 million and $8.7 million at December 31, 2023 and 2022, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2023**	**2022**	**2023**	**2022**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 252,879	$ 345,135	$ 44,661	$ 61,025
Service cost	—	3,389	56	126
Interest cost	11,921	10,580	2,146	1,444
Curtailments	—	(19,736)	—	—
Settlements	—	(13,295)	—	—
Actuarial loss (gain)	11,548	(51,275)	25	(14,191)
Benefits paid	(32,374)	(21,919)	(3,526)	(3,743)
Benefit obligation at December 31	**$ 243,974**	**$ 252,879**	**$ 43,362**	**$ 44,661**
Change in plan assets				
Fair value of plan assets at January 1	$ 201,556	$ 291,097	$ —	$ —
Actual return on plan assets	15,317	(54,327)	—	—
Employer and plan participants' contributions	—	—	3,526	3,743
Settlements	—	(13,295)	—	—
Benefits paid	(32,374)	(21,919)	(3,526)	(3,743)
Fair value of plan assets at December 31	**$ 184,499**	**$ 201,556**	**$ —**	**$ —**
Funded status	**$ (59,475)**	**$ (51,323)**	**$ (43,362)**	**$ (44,661)**

During 2023, the pension benefit obligation had an actuarial loss of $11.5 million, primarily due to a $5.4 million loss from increases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

During 2022, the pension benefit obligation had an actuarial gain of $51.3 million, primarily due to a $50.8 million gain from decreases in discount rates. In 2022, the pension benefit obligation had a reduction of $13.3 million from settlements and $19.7 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. During 2022, the postretirement benefit obligation had an actuarial gain of $14.2 million, primarily due to a $9.9 million gain from increases in discount rates.

Amounts recognized in the balance sheet as of December 31, 2023 and 2022 consisted of:

Amounts recognized in the balance sheet		Pension Benefits		Postretirement Benefits	
December 31,		2023	2022	2023	2022
(Thousands)					
Other current liabilities	$	—	$ —	$ (4,720)	$ (4,881)
Pension and other postretirement benefits		(59,475)	(51,323)	(38,642)	(39,780)
Total	**$**	**(59,475)**	**$ (51,323)**	**$ (43,362)**	**$ (44,661)**

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	
December 31,		2023	2022	2023	2022
(Thousands)					
Net loss (gain)	$	22,288	$ 13,234	$ (16,486)	$ (18,597)
Prior service credit		—	—	(1,237)	(1,461)

Our accumulated benefit obligation for all qualified defined benefit pension plans was $244.0 million at December 31, 2023 and $252.9 million at December 31, 2022.

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, 2023 and 2022. 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, 2023 and 2022.

December 31,		2023		2022
(Thousands)				
Projected benefit obligation	$	243,974	$	252,879
Accumulated benefit obligation	$	243,974	$	252,879
Fair value of plan assets	$	184,499	$	201,556

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2023 and 2022.

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, 2023 and 2022 consisted of:

Years Ended December 31,	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
(Thousands)				
Net periodic benefit cost				
Service cost	$ —	$ 3,389	$ 56	$ 126
Interest cost	11,921	10,580	2,146	1,444
Expected return on plan assets	(13,265)	(13,886)	—	—
Amortization of prior service credit	—	—	(224)	(356)
Amortization of net loss (gain)	441	8,257	(2,087)	(413)
Settlement charge	—	696	—	—
Net periodic benefit cost	**$ (903)**	**$ 9,036**	**$ (109)**	**$ 801**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ 9,495	$ 16,938	$ 24	$ (14,191)
Amortization of net loss (gain)	(441)	(8,257)	2,087	413
Settlement charge	—	(696)	—	—
Effect of curtailments on gain	—	(19,737)	—	—
Amortization of prior service credit	—	—	224	356
Total recognized in regulatory assets and regulatory liabilities	**$ 9,054**	**$ (11,752)**	**$ 2,335**	**$ (13,422)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ 8,151**	**$ (2,716)**	**$ 2,226**	**$ (12,621)**

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, 2023 and 2022 consisted of:

	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2023	Postretirement Benefits 2022
Discount rate	4.70%	5.08%	4.66%	5.08%
Rate of compensation increase	N/A	N/A	N/A	N/A
Interest crediting rate	2.75%	4.48%	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, 2023 and 2022 consisted of:

	Pension Benefits		Postretirement Benefits	
	2023	2022	2023	2022
Discount rate	5.08%	2.31% / 3.55% / 4.94%	5.08%	2.47%
Expected long-term return on plan assets	6.00%	6.00% / 5.50%	N/A	N/A
Rate of compensation increase	N/A	Age-Related / 3.00% Union	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.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2023 and 2022 consisted of:

	2023	2022
Health care cost trend rate (pre 65/post 65)	8.10% / 8.60%	6.25% / 7.00%
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	2031 / 2032	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 2024. We expect to contribute $4.7 million to our postretirement benefit plans during 2024.

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)			
2024	$ 36,135	$ 4,720	$ —
2025	$ 30,452	$ 4,557	$ —
2026	$ 27,563	$ 4,401	$ —
2027	$ 25,333	$ 4,209	$ —
2028	$ 22,951	$ 4,005	$ —
2029-2033	$ 85,755	$ 16,833	$ —

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 15%-70% for Return-Seeking assets and 30%-85% 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, 2023, consisted of:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Level 1**	**Level 2**	**Level 3**
(Thousands)				
2023				
Cash and cash equivalents	$ 5,068	$ (5)	$ 5,073	$ —
U.S. government securities	28,474	28,474	—	—
Common stocks	2,874	2,874	—	—
Registered investment companies	8,879	8,879	—	—
Corporate bonds	70,520	—	70,520	—
Common collective trusts	24,123	—	24,123	—
Other investments, principally annuity and fixed income	1,885	—	1,885	—
	$ 141,823	**$ 40,222**	**$ 101,601**	**$ —**
Other investments measured at net asset value	42,676			
Total	**$ 184,499**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

Asset Category		Total		Fair Value Measurements at December 31, Using Level 1		Level 2		Level 3
(Thousands)								
2022								
Cash and cash equivalents	$	6,233	$	5	$	6,228	$	—
U.S. government securities		29,378		29,378		—		—
Common stocks		3,015		3,015		—		—
Registered investment companies		9,286		9,286		—		—
Corporate bonds		73,711		—		73,711		—
Preferred stocks		91		91		—		—
Common collective trusts		29,799		—		29,799		—
Other investments, principally annuity and fixed income		2,539		—		2,539		—
	$	**154,052**	**$**	**41,775**	**$**	**112,277**	**$**	**—**
Other investments measured at net asset value		47,504						
Total	**$**	**201,556**						

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, 2023 and 2022.

Note 15. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2023 and 2022, consisted of:

Years Ended December 31,		2023		2022
(Thousands)				
Allowance for funds used during construction		11,321		12,945
Carrying costs on regulatory assets		7,812		5,247
Miscellaneous		578		196
Total other income	**$**	**19,711**	**$**	**18,388**
Pension non-service components	$	666	$	(6,781)
Miscellaneous		(7,104)		(1,941)
Total other deductions	**$**	**(6,438)**	**$**	**(8,722)**

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 $83.7 million in 2023 and $75.1 million in 2022. Cost for services includes amounts capitalized in utility plant, which was approximately $13.4 million in 2023 and $13.6 million in 2022. 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 $22.8 million in 2023 and $25.3 million in 2022. 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 $58.4 million at December 31, 2023 and $54.1 million at December 31, 2022 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $2.9 million at December 31, 2023 and $3.6 million at December 31, 2022 is from various companies.

There were no notes receivable from affiliates at December 31, 2023 and December 31, 2022. 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, 2024, which is the date these financial statements were available to be issued.