# The Berkshire Gas Company

## Financial Statements

## As of and for the Years Ended December 31, 2024 and 2023

## The Berkshire Gas Company

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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, 2024 and 2023, 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, 2024 and 2023, 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 28, 2025

## The Berkshire Gas Company
## Statements of Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Operating Revenues** | $ | **92,663** | $ | **96,584** |
| **Operating Expenses** | | | | |
| Natural gas purchased | | 26,485 | | 27,025 |
| Operations and maintenance | | 43,382 | | 38,206 |
| Depreciation and amortization | | 10,173 | | 9,313 |
| Taxes other than income taxes, net | | 8,275 | | 7,581 |
| **Total Operating Expenses** | | **88,315** | | **82,125** |
| **Operating Income** | | **4,348** | | **14,459** |
| Other income | | 1,207 | | 1,064 |
| Other deductions | | (621) | | (333) |
| Interest expense, net of capitalization | | (4,066) | | (3,071) |
| **Income Before Tax** | | **868** | | **12,119** |
| Income tax expense | | 246 | | 3,203 |
| **Net Income** | $ | **622** | $ | **8,916** |

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

## The Berkshire Gas Company
## Statements of Comprehensive Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Net Income** | $ | **622** | $ | **8,916** |
| **Other Comprehensive Income (Loss), Net of Tax** | | | | |
| Remeasurement of non-qualified plan, net of income tax benefit of $0 for 2024 and ($21) for 2023 | | — | | (57) |
| **Other Comprehensive Income (Loss), Net of Tax** | | **—** | | **(57)** |
| **Comprehensive Income** | $ | **622** | $ | **8,859** |

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

## The Berkshire Gas Company
## Balance Sheets

| As of December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Assets** | | | | |
| **Current Assets** | | | | |
| Cash and cash equivalents | $ | 3,493 | $ | 488 |
| Accounts receivable and unbilled revenues, net | | 18,214 | | 16,812 |
| Accounts receivable from affiliates | | 53 | | 5 |
| Notes receivable from affiliates | | 15,000 | | — |
| Fuel and gas in storage | | 3,403 | | 3,538 |
| Materials and supplies | | 2,858 | | 3,344 |
| Other current assets | | 2,125 | | 684 |
| Regulatory assets | | 17,787 | | 14,396 |
| **Total Current Assets** | | **62,933** | | **39,267** |
| Utility plant, at original cost | | 376,012 | | 349,882 |
| Less accumulated depreciation | | (112,376) | | (107,271) |
| **Net Utility Plant in Service** | | **263,636** | | **242,611** |
| Construction work in progress | | 5,973 | | 3,144 |
| **Total Utility Plant** | | **269,609** | | **245,755** |
| Operating lease right-of-use assets | | 92 | | 100 |
| Other property and investments | | 2,197 | | 2,170 |
| **Regulatory and Other Assets** | | | | |
| Regulatory assets | | 16,645 | | 18,728 |
| Goodwill | | 51,932 | | 51,932 |
| Other | | 30 | | 16 |
| **Total Regulatory and Other Assets** | | **68,607** | | **70,676** |
| **Total Assets** | **$** | **403,438** | **$** | **357,968** |

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

# The Berkshire Gas Company
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| **(Thousands)** | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Notes payable to affiliates | $ — | $ 17,200 |
| Accounts payable and accrued liabilities | 14,831 | 14,934 |
| Accounts payable to affiliates | 5,516 | 5,371 |
| Interest accrued | 1,019 | 818 |
| Taxes accrued | 3,998 | 1,692 |
| Operating lease liabilities | 7 | 7 |
| Regulatory liabilities | 2,306 | 463 |
| Other | 4,641 | 4,159 |
| **Total Current Liabilities** | **32,318** | **44,644** |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | 52,145 | 51,866 |
| **Other Non-current Liabilities** | | |
| Deferred income taxes | 33,784 | 32,790 |
| Pension and other postretirement | 9,584 | 12,779 |
| Operating lease liabilities | 85 | 92 |
| Environmental remediation costs | 1,427 | 1,978 |
| Other | 1,318 | 1,333 |
| **Total Regulatory and Other Liabilities** | **98,343** | **100,838** |
| Non-current debt | 104,377 | 59,642 |
| **Total Liabilities** | **235,038** | **205,124** |
| **Commitments and Contingencies** | | |
| **Common Stock Equity** | | |
| Additional paid-in capital | 141,438 | 126,504 |
| Retained earnings | 26,962 | 26,340 |
| **Total Common Stock Equity** | **168,400** | **152,844** |
| **Total Liabilities and Equity** | **$ 403,438** | **$ 357,968** |

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

## The Berkshire Gas Company
## Statements of Cash Flows

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Cash Flow From Operating Activities:** | | |
| **Net income** | **$ 622** | **$ 8,916** |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 10,173 | 9,313 |
| Regulatory assets/liabilities amortization | 893 | 242 |
| Regulatory assets/liabilities carrying cost | (704) | (858) |
| Amortization of debt issuance costs | 51 | 47 |
| Deferred taxes | 813 | 2,127 |
| Pension cost | 315 | 792 |
| Stock-based compensation | 22 | 51 |
| Gain on disposal of assets | — | (76) |
| Other non-cash items | 91 | (124) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable, from affiliates, and unbilled revenues | (1,450) | 2,892 |
| Inventories | 621 | (197) |
| Accounts payable, to affiliates, and accrued liabilities | 1,278 | (9,539) |
| Taxes accrued | 2,252 | 4,069 |
| Other assets/liabilities | 945 | (46) |
| Regulatory assets/liabilities | (6,585) | 673 |
| **Net Cash Provided by Operating Activities** | **9,337** | **18,282** |
| **Cash Flow From Investing Activities:** | | |
| Capital expenditures | (34,088) | (26,779) |
| Contributions in aid of construction | 270 | 567 |
| Proceeds from sale of property, plant and equipment | 34 | 200 |
| Notes receivable from affiliates | (15,000) | — |
| **Net Cash Used in Investing Activities** | **(48,784)** | **(26,012)** |
| **Cash Flow From Financing Activities:** | | |
| Non-current debt issuance | 44,652 | — |
| Notes payable to affiliates | (17,200) | 7,550 |
| Capital contributions | 15,000 | — |
| **Net Cash Provided by Financing Activities** | **42,452** | **7,550** |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | **3,005** | **(180)** |
| **Cash and Cash Equivalents, Beginning of Period** | **488** | **668** |
| **Cash and Cash Equivalents, End of Period** | **$ 3,493** | **$ 488** |

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, 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** |
| Net income | — | — | — | 622 | | 622 |
| Stock-based compensation | — | — | (66) | — | — | (66) |
| Capital contributions | — | — | 15,000 | — | — | 15,000 |
| **Balance at December 31, 2024** | **100** | **$ —** | **$ 141,438** | **$ 26,962** | **$ —** | **$ 168,400** |

(*) 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 40,700 customers in its service area totaling 738 square miles as of December 31, 2024. 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. (AGR), which is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Agreement and Plan of Merger:*** On May 17, 2024, AGR entered into an Agreement and Plan of Merger (the Merger Agreement) with Iberdrola and Arizona Merger Sub, Inc (Merger Sub). As a result of the consummation of the Merger on December 23, 2024 (closing date), Merger Sub merged with and into Avangrid (the Merger), with Avangrid continuing as the surviving corporation and a wholly-owned subsidiary of Iberdrola. On the closing date, each share of common stock issued and outstanding immediately prior to the closing date (other than common stock owned by the Merger, Merger Sub or any other direct or indirect wholly-owned Subsidiary of the Merger, and in each case not held on behalf of the third parties (collectively, the Excluded Shares)) was converted into a right to receive $35.75 per share of common stock in cash, without interest.

On the closing date, (i) all shares of common stock ceased to be outstanding, were cancelled and ceased to exist and (ii) each Excluded Share ceased to be outstanding and was cancelled without payment of any consideration and ceased to exist. As a result of the consummation of the Merger on December 23, 2024, Iberdrola became the direct owner of 100 shares of common stock of Avangrid which represents the only outstanding capital of the Company. On the closing date, the New York Stock Exchange (NYSE) filed with the Securities and Exchange Commission (the SEC) a notification of removal from listing on Form 25 in order to delist the common stock from the NYSE and deregister the common stock under Section 12(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Following the effectiveness of the Form 25, on January 2, 2025, Avangrid filed with the SEC a Form 15 requesting the termination of registration of the common stock under Section 12(g) of the Exchange Act and the suspension of reporting obligations under Section 13 and 15(d) of the Exchange Act with respect to the common stock.

***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.

## Notes to Financial Statements

***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 2.5% of average depreciable property for 2024 and 2.4% of average depreciable property for 2023. We amortize our capitalized software cost, using the straight-line method, based on useful lives of 6 to 12 years. Depreciation expense was $9.0 million in 2024 and $8.2 million in 2023. Amortization of capitalized software was $1.2 million in 2024 and $1.1 million in 2023.

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)** | | **2024** | | **2023** |
|---|---|---|---|---|---|
| **(Thousands)** | | | | | |
| Gas distribution plant | 4-68 | $ | 306,658 | $ | 284,440 |
| Software | 6-12 | | 15,367 | | 13,152 |
| Land | | | 2,305 | | 2,305 |
| Buildings and improvements | 50-55 | | 34,223 | | 33,358 |
| Other plant | 25-55 | | 17,459 | | 16,627 |
| **Utility plant at original cost** | | | **376,012** | | **349,882** |
| Less accumulated depreciation | | | (112,376) | | (107,271) |
| **Net Utility Plant in Service** | | | **263,636** | | **242,611** |
| Construction work in progress | | | 5,973 | | 3,144 |
| **Total Utility Plant** | | **$** | **269,609** | **$** | **245,755** |

***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:

| | 2024 | 2023 |
|---|---|---|
| **(Thousands)** | | |
| **Cash paid (refunded) during the years ended December 31:** | | |
| Interest, net of amounts capitalized | $ 3,611 | $ 2,158 |
| Income taxes refunded, net | $ (1,199) | $ (2,790) |

Of the income taxes refunded, substantially all were refunded by AGR under the tax sharing agreement. Interest capitalized was $0.3 million in 2024 and $0.5 million in 2023, respectively. Accrued liabilities for utility plant additions were $7.5 million at December 31, 2024 and $8.7 million at December 31, 2023.

***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 $8.7 million for 2024 and $6.9 million for 2023, and are shown net of an allowance for credit losses at December 31 of $2.4 million for 2024 and $3.0 million for 2023. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $1.4 million in 2024 and $1.5 million in 2023.

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 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, 2024 and 2023.

***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.

***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 is $2.1 million and $1.6 million at December 31, 2024 and 2023, 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 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, 2024 and 2023.

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 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, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2024 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 standard is required to be adopted by private entities for the annual periods beginning after December 15, 2025. Early adoption is permitted. The two primary enhancements relate to disaggregation of the annual effective tax rate reconciliation and income taxes paid disclosures. 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) 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 collective bargaining agreements. We have no agreements that will expire within the coming year.

## Note 2. Industry Regulation

### Rates

Utilities are entitled by Massachusetts statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

On June 24, 2022, Berkshire filed a Settlement Agreement with the Massachusetts Attorney General's Office (AGO) for DPU approval. The Settlement Agreement was approved in its entirety by the DPU on October 27, 2022, and new rates went into effect January 1, 2023. Berkshire continues to charge the 2023 rates which include an approved 9.7% ROE and a 54% equity ratio. Berkshire has agreed not to request new distribution rates to be in effect prior to November 1, 2025.

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 $13.9 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 to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Regulatory assets at December 31, 2024 and 2023 consisted of:

| **December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| Deferred purchased gas | $ | 3,033 | $ | 3,619 |
| Energy efficiency programs | | 8,769 | | 2,752 |
| Environmental remediation costs | | 3,751 | | 4,250 |
| Pension and other postretirement benefits | | 12,440 | | 13,844 |
| Recoverable bad debt | | 930 | | 1,300 |
| Revenue decoupling mechanism | | 2,401 | | 4,868 |
| Unfunded future income taxes | | 340 | | 410 |
| Other | | 2,768 | | 2,081 |
| **Total regulatory assets** | | **34,432** | | **33,124** |
| Less: current portion | | 17,787 | | 14,396 |
| **Total non-current regulatory assets** | **$** | **16,645** | **$** | **18,728** |

Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.

## Notes to Financial Statements

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 over a seven-year period through an annual surcharge. 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 gas system enhancement.

Regulatory liabilities at December 31, 2024 and 2023 consisted of:

| **December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| Asset removal obligations | $ | 40,484 | $ | 40,091 |
| Pension and other postretirement benefits | | 1,892 | | 889 |
| Tax Act – remeasurement | | 10,879 | | 11,060 |
| Other | | 1,196 | | 289 |
| **Total regulatory assets** | | **54,451** | | **52,329** |
| Less: current portion | | 2,306 | | 463 |
| **Total non-current regulatory assets** | **$** | **52,145** | **$** | **51,866** |

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, 2024 and 2023 are as follows:

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Regulated operations – natural gas | $ 90,779 | $ 92,541 |
| Other (a) | 1,303 | 229 |
| **Revenue from contracts with customers** | **92,082** | **92,770** |
| Alternative revenue programs | 860 | 3,740 |
| Other revenue | (279) | 74 |
| **Total operating revenues** | **$ 92,663** | **$ 96,584** |

(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 2024 and 2023 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2024 or 2023 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, 2024 and 2023, with no accumulated impairment losses and no changes during 2024 and 2023.

## Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2024 and 2023 consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Current | | | | |
| Federal | $ | 1,322 | $ | 323 |
| State | | (1,889) | | 753 |
| **Current taxes charged to expense (benefit)** | | **(567)** | | **1,076** |
| Deferred | | | | |
| Federal | | (1,174) | | 1,905 |
| State | | 1,987 | | 222 |
| **Deferred taxes charged to expense** | | **813** | | **2,127** |
| **Total Income Tax Expense** | **$** | **246** | **$** | **3,203** |

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2024 and 2023, respectively, consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Tax expense at federal statutory rate | $ | 182 | $ | 2,545 |
| Excess ADIT amortization | | (132) | | (132) |
| State tax expense, net of federal benefit | | 77 | | 770 |
| Other, net | | 119 | | 20 |
| **Total Income Tax Expense** | **$** | **246** | **$** | **3,203** |

Income tax expense for the year ended December 31, 2024 was $0.1 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 28.3%. 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 ADIT amortization. This resulted in an effective tax rate of 26.4%.

Deferred tax assets and liabilities as of December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
| --- | --- | --- | --- | --- |
| (Thousands) | | | | |
| **Non-current Deferred Income Tax Liabilities (Assets)** | | | | |
| Property related | $ | 38,325 | $ | 33,663 |
| 2017 Tax Act measurement | | (2,972) | | (3,022) |
| Federal and state tax credits | | (2,151) | | — |
| Federal and state net operating loss | | (5,180) | | (2,040) |
| Pension and other postretirement benefits | | (84) | | 313 |
| Gas supply charges | | 942 | | 1,344 |
| Other | | 4,904 | | 2,532 |
| **Total Non-current Deferred Income Tax Liabilities** | **$** | **33,784** | **$** | **32,790** |
| Deferred tax assets | | 10,387 | | 5,062 |
| Deferred tax liabilities | | 44,171 | | 37,852 |
| **Net Accumulated Deferred Income Tax Liabilities** | **$** | **33,784** | **$** | **32,790** |

Berkshire has federal net operating losses of $4.3 million and $1.4 million for the years ended December 31, 2024 and 2023, respectively. Berkshire has net state net operating losses of $0.9 million and $0.6 million for the year ended December 31, 2024 and 2023, respectively.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2024 and 2023.

### Note 7. Long-term Debt

Long-term debt as of December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | | 2023 | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| (Thousands) | Maturity Dates | | Balances | Interest Rates | | Balances | Interest Rates |
| Senior unsecured notes | 2029-2050 | $ | 105,000 | 3.68%-5.66% | $ | 60,000 | 3.68%-5.33% |
| Unamortized debt issuance cost and discount | | | (623) | | | (358) | |
| **Total Debt** | | | **104,377** | | | **59,642** | |
| Less: debt due within one year, included in current liabilities | | | — | | | — | |
| **Total Non-current Debt** | | **$** | **104,377** | | **$** | **59,642** | |

On November 20, 2024, Berkshire issued $45 million of unsecured notes maturing in 2035 at an interest rate of 5.66%.

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

| | 2025 | | 2026 | | 2027 | | 2028 | | 2029 | | Total |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| (Thousands) | | | | | | | | | | | |
| $ | — | $ | — | $ | — | $ | — | $ | 20,000 | $ | 20,000 |

We have no financial debt covenant requirements related to our long-term debt at December 31, 2024 and 2023.

## Note 8. Bank Loans and Other Borrowings

Berkshire had no notes payable outstanding balance as of December 31, 2024 and $17.2 million notes payable outstanding as of December 31, 2023. Berkshire funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility), and a bank provided credit facility to which Berkshire is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. Berkshire has a lending/ borrowing limit of $15 million under this agreement. Berkshire had no outstanding balance under this agreement as of December 31, 2024 and $15.0 million debt outstanding as of December 31, 2023.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $50 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. Berkshire had no outstanding balance under this agreement as of December 31, 2024 and $2.2 million debt outstanding under this agreement as of December 31, 2023.

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. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates. 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, 2024 and 2023.

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, 2024. We are not in default as of December 31, 2024.

**Note 9. Leases**

We have operating leases for land rights. As of December 31, 2024 and 2023, 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 13 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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Lease cost** | | |
| Operating lease cost | $ 10 | $ 10 |
| Short-term lease cost | 42 | 35 |
| **Total lease cost** | **$ 52** | **$ 45** |

Balance sheet and other information for the years ended December 31, 2024 and 2023 was as follows:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except lease term and discount rate) | | |
| **Operating Leases** | | |
| Operating lease right-of-use assets | $ 92 | $ 100 |
| | | |
| Operating lease liabilities, current | 7 | 7 |
| Operating lease liabilities, long-term | 85 | 92 |
| Total operating lease liabilities | $ 92 | $ 99 |
| | | |
| **Weighted-average Remaining Lease Term (years):** | | |
| Operating leases | 10.95 | 11.95 |
| **Weighted-average Discount Rate:** | | |
| Operating leases | 2.95 % | 2.94 % |

Supplemental cash flows information related to leases was as follows:

| For the Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash flows from operating leases | $ 9 | $ 9 |
| | | |
| Right-of-use assets obtained in exchange for lease obligations: | | |
| Operating leases | $ — | $ 2 |

As of December 31, 2024, maturities of lease liabilities were as follows:

| | Operating Leases |
|---|---|
| (Thousands) | |
| **Years ending December 31,** | |
| 2025 | $ 9 |
| 2026 | 9 |
| 2027 | 10 |
| 2028 | 10 |
| 2029 | 10 |
| Thereafter | 61 |
| **Total lease payments** | **109** |
| Less: imputed interest | (17) |
| **Total** | **$ 92** |

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, 2024 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 $0.3 million and has recorded a liability and offsetting regulatory asset for such expenses as of December 31, 2024. 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, 2024, we have accrued approximately $1.6 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 2040.

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

The estimated fair value of debt amounted to $97 million as December 31, 2024 and $53 million as of December 31, 2023. 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, 2024 and 2023 consisted of:

| **Description** | **Level 1** | **Level 2** | **Level 3** | **Total** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **2024** | | | | |
| **Assets** | | | | |
| Non-current investments | $ 2,197 | $ — | $ — | $ 2,197 |
| **Total** | **$ 2,197** | **$ —** | **$ —** | **$ 2,197** |
| | | | | |
| **2023** | | | | |
| **Assets** | | | | |
| Non-current investments | $ 2,170 | $ — | $ — | $ 2,170 |
| **Total** | **$ 2,170** | **$ —** | **$ —** | **$ 2,170** |

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2024. 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 $1.2 million in 2024 and $1.1 million in 2023.

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 $1.0 million and $1.1 million at December 31, 2024 and 2023, respectively.

### Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2024 and 2023 consisted of:

| As of December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Change in benefit obligation** | | | | |
| Benefit obligation at January 1 | $ 37,435 | $ 37,686 | $ 2,195 | $ 1,672 |
| Service cost | 86 | 148 | 25 | 24 |
| Interest cost | 1,712 | 1,865 | 97 | 81 |
| Curtailments | (407) | — | — | — |
| Actuarial (gain) loss | (2,114) | 1,435 | (140) | 483 |
| Benefits paid | (3,266) | (3,699) | (116) | (65) |
| **Benefit obligation at December 31** | **$ 33,446** | **$ 37,435** | **$ 2,061** | **$ 2,195** |
| **Change in plan assets** | | | | |
| Fair value of plan assets at January 1 | 26,683 | 26,679 | — | — |
| Actual return on plan assets | 617 | 3,351 | — | — |
| Employer contributions | 1,661 | 352 | 116 | 65 |
| Benefits paid | (3,266) | (3,699) | (116) | (65) |
| **Fair value of plan assets at December 31** | **$ 25,695** | **$ 26,683** | **$ —** | **$ —** |
| **Funded status** | **$ (7,751)** | **$ (10,752)** | **$ (2,061)** | **$ (2,195)** |

During 2024, the pension benefit obligation had an actuarial gain of $2.1 million primarily due to $2.3 million gain from increases in discount rates. In 2024, the pension benefit obligation had a reduction of $0.4 million from curtailments.There were no significant gains or losses relating to the postretirement benefit obligations in 2024.

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.

Amounts recognized in the balance sheet as of December 31, 2024 and 2023 consisted of:

| December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Other current liabilities | $ — | $ — | $ (220) | $ (229) |
| Pension and other postretirement benefits | (7,751) | (10,752) | (1,841) | (1,966) |
| **Total** | **$ (7,751)** | **$ (10,752)** | **$ (2,061)** | **$ (2,195)** |

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

| December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Net loss (gain) | $ 2,601 | $ 4,255 | $ (782) | $ (714) |

Our accumulated benefit obligation for all qualified defined benefit pension plans was $33.4 million at December 31, 2024 and $36.9 million at December 31, 2023.

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, 2024 and 2023. 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, 2024 and 2023.

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Projected benefit obligation | $ | 33,446 | $ | 37,435 |
| Accumulated benefit obligation | $ | 33,446 | $ | 36,909 |
| Fair value of plan assets | $ | 25,695 | $ | 26,683 |

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2024 and 2023.

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, 2024 and 2023 consisted of:

| | Pension Benefits | | | | Postretirement Benefits | | | |
|---|---|---|---|---|---|---|---|---|
| **Years Ended December 31,** | | **2024** | | **2023** | | **2024** | | **2023** |
| (Thousands) | | | | | | | | |
| Net periodic benefit cost | | | | | | | | |
| Service cost | $ | 86 | $ | 148 | $ | 25 | $ | 24 |
| Interest cost | | 1,712 | | 1,865 | | 97 | | 81 |
| Expected return on plan assets | | (1,648) | | (1,528) | | — | | — |
| Amortization of actuarial loss (gain) | | 165 | | 307 | | (71) | | (133) |
| **Net periodic benefit cost** | **$** | **315** | **$** | **792** | **$** | **51** | **$** | **(28)** |
| **Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities** | | | | | | | | |
| Net (gain) loss | $ | (1,082) | $ | (389) | $ | (140) | $ | 483 |
| Amortization of actuarial (loss) gain | | (165) | | (307) | | 71 | | 113 |
| Curtailment charge | | (407) | | — | | — | | — |
| **Total recognized in regulatory assets and regulatory liabilities** | | **(1,654)** | | **(696)** | | **(69)** | | **596** |
| **Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities** | **$** | **(1,339)** | **$** | **96** | **$** | **(18)** | **$** | **568** |

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, 2024 and 2023 consisted of:

| As of December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| Discount rate | 5.41% | 4.69% | 5.19% | 4.66% |
| Rate of compensation increase | N/A | 2.50% for Union | N/A | N/A |
| Interest crediting rate | 3.00% | 2.75% | 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, 2024 and 2023 consisted of:

| As of December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| Discount rate | 4.69%/5.10% | 5.21% | 4.66% | 5.08% |
| Expected long-term return on plan assets | 7.50%/7.50% | 7.50% | N/A | N/A |
| Rate of compensation increase | 2.50% for Union / N/A | 2.50% for 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 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, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| Health care cost trend rate (pre 65/post 65) | 8.90% / 10.60% | 8.10% / 8.60% |
| 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 | 2039 / 2039 | 2031 / 2032 |

***Contributions***: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $1.0 million to our pension and $0.2 million to our other postretirement benefit plans during 2025.

***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) | | | |
| 2025 | $ 3,510 | $ 220 | $ — |
| 2026 | $ 2,984 | $ 229 | $ — |
| 2027 | $ 2,887 | $ 222 | $ — |
| 2028 | $ 2,843 | $ 217 | $ — |
| 2029 | $ 2,816 | $ 199 | $ — |
| 2030 - 2034 | $ 12,727 | $ 913 | $ — |

***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, 2024, consisted of:

## Notes to Financial Statements

| Asset Category | | Total | | Fair Value Measurements at December 31, Using Level 1 | | Level 2 | | Level 3 |
|---|---|---|---|---|---|---|---|---|
| (Thousands) | | | | | | | | |
| **2024** | | | | | | | | |
| Cash and cash equivalents | $ | 1,009 | $ | 59 | $ | 950 | $ | — |
| U.S. government securities | | 2,560 | | 2,560 | | — | | — |
| Common stocks | | 1,296 | | 1,296 | | — | | — |
| Registered investment companies | | 2,354 | | 2,354 | | — | | — |
| Corporate bonds | | 3,551 | | — | | 3,551 | | — |
| Common collective trusts | | 9,347 | | — | | 9,347 | | — |
| Other investments, principally annuity and fixed income | | 19 | | — | | 19 | | — |
| | **$** | **20,136** | **$** | **6,269** | **$** | **13,867** | **$** | **—** |
| Other investments measured at net asset value | | 5,559 | | | | | | |
| **Total** | **$** | **25,695** | | | | | | |

The fair values of pension benefits plan assets, by asset category, as of December 31, 2023, consisted of:

| Asset Category | | Total | | Fair Value Measurements at December 31, Using 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** | | | | | | |

*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 Iberdrola common stock as of both December 31, 2024 and 2023.

**Note 13. Other Income and Other Deductions**

Other income and deductions for the years ended December 31, 2024 and 2023, consisted of:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Allowance for funds used during construction | $ — | $ 39 |
| Carrying costs on regulatory assets | 1,211 | 1,073 |
| Interest and dividend income | 30 | — |
| Miscellaneous | (34) | (48) |
| **Total other income** | **$ 1,207** | **$ 1,064** |
| Pension non-service components | (42) | 129 |
| Miscellaneous | (579) | (462) |
| **Total other deductions** | **$ (621)** | **$ (333)** |

**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 $9.5 million in 2024 and $6.7 million in 2023. Cost for services includes amounts capitalized in utility plant, which was approximately $1.1 million in 2024 and $0.5 million in 2023. The remainder was primarily recorded as operations and maintenance expense.

The balances in accounts payable to affiliates of $5.5 million at December 31, 2024 and $5.4 million at December 31, 2023 are mostly payable to UIL Holdings and Avangrid Service Company. The balance in accounts receivable from affiliates of $0.1 million at December 31, 2024 and $0.01 at December 31, 2023 is mostly receivable from UIL Holdings and SCG.

There were $15.0 million in notes receivable from SCG at December 31, 2024 and no notes receivable from affiliates at December 31, 2023. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

## Note 15. Subsequent Events

The company has performed a review of subsequent events through March 28, 2025, which is the date these 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, 2024 and 2023

**Central Maine Power Company**
**and Subsidiaries**

**Index**

KPMG LLP
Two Financial Center
60 South Street
Boston, MA 02111

## Independent Auditors' Report

Shareholder and Board of Directors
Central Maine Power Company:

*Opinion*

We have audited the consolidated financial statements of Central Maine Power Company and its subsidiaries (the Company), which comprise the consolidated balance sheets as of December 31, 2024 and 2023, 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, 2024 and 2023, 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

Boston, Massachusetts
March 25, 2025

## Central Maine Power Company and Subsidiaries
## Consolidated Statements of Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Operating Revenues** | $ | **1,274,872** | $ | **1,127,381** |
| **Operating Expenses** | | | | |
| Electricity purchased | | 128,535 | | 103,393 |
| Operations and maintenance | | 686,727 | | 578,500 |
| Depreciation and amortization | | 138,014 | | 131,383 |
| Taxes other than income taxes, net | | 75,465 | | 79,134 |
| **Total Operating Expenses** | | **1,028,741** | | **892,410** |
| **Operating Income** | | **246,131** | | **234,971** |
| Other income | | 37,811 | | 25,447 |
| Other income (deductions), net | | 11 | | (1,279) |
| Interest expense, net of capitalization | | (70,443) | | (66,121) |
| **Income Before Income Tax** | | **213,510** | | **193,018** |
| Income tax expense | | 32,096 | | 21,126 |
| **Net Income** | | **181,414** | | **171,892** |
| Less: net income attributable to noncontrolling interest | | 3,404 | | 3,288 |
| **Net Income Attributable to CMP** | $ | **178,010** | $ | **168,604** |

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, | | 2024 | | 2023 |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Net Income** | $ | **181,414** | $ | **171,892** |
| **Other Comprehensive Income, Net of Tax** | | | | |
| Amortization of pension cost for nonqualified plans and current year actuarial gain, net of income tax | | 36 | | 29 |
| Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax | | 130 | | 130 |
| **Other Comprehensive Income, Net of Tax** | | **166** | | **159** |
| **Comprehensive Income** | | **181,580** | | **172,051** |
| Less: | | | | |
| Comprehensive income attributable to noncontrolling interest | | 3,404 | | 3,288 |
| **Comprehensive Income Attributable to CMP** | $ | **178,176** | $ | **168,763** |

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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 21,690 | $ 52,570 |
| Accounts receivable and unbilled revenues, net | 324,433 | 336,664 |
| Accounts receivable from affiliates | 25,491 | 2,399 |
| Notes receivable from affiliates | 247 | 252 |
| Materials and supplies | 72,080 | 68,495 |
| Prepayments and other current assets | 27,537 | 30,715 |
| Income tax receivable | — | 3,376 |
| Regulatory assets | 278,267 | 153,887 |
| **Total Current Assets** | **749,745** | **648,358** |
| Utility plant, at original cost | 5,817,310 | 5,466,800 |
| Less accumulated depreciation | (1,701,598) | (1,588,777) |
| **Net Utility Plant in Service** | **4,115,712** | **3,878,023** |
| Construction work in progress | 350,737 | 317,707 |
| **Total Utility Plant** | **4,466,449** | **4,195,730** |
| Operating lease right-of-use assets | 15,958 | 14,374 |
| Other property and investments | 1,087 | 1,020 |
| **Regulatory and Other Assets** | | |
| Regulatory assets | 639,761 | 577,482 |
| Goodwill | 324,938 | 324,938 |
| Other | 154,572 | 157,372 |
| **Total Regulatory and Other Assets** | **1,119,271** | **1,059,792** |
| **Total Assets** | **$ 6,352,510** | **$ 5,919,274** |

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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Current portion of debt | $ 79,373 | $ — |
| Notes payable to affiliates | 92,400 | 54,400 |
| Accounts payable and accrued liabilities | 391,166 | 448,582 |
| Accounts payable to affiliates | 39,620 | 41,385 |
| Interest accrued | 20,100 | 18,747 |
| Taxes accrued | 18,137 | 3,399 |
| Operating lease liabilities | 1,104 | 1,117 |
| Other current liabilities | 118,762 | 125,844 |
| Regulatory liabilities | 10,054 | 80,048 |
| **Total Current Liabilities** | **770,716** | **773,522** |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | 280,179 | 307,999 |
| **Other Non-current liabilities** | | |
| Deferred income taxes | 850,657 | 773,650 |
| Pension and other postretirement | 72,881 | 77,595 |
| Operating lease liabilities | 16,741 | 14,764 |
| Other | 143,191 | 143,435 |
| **Total Regulatory and Other Liabilities** | **1,363,649** | **1,317,443** |
| Non-current debt | 1,504,985 | 1,410,241 |
| **Total Liabilities** | **3,639,350** | **3,501,206** |
| **Commitments and Contingencies** | | |
| **Redeemable Preferred Stock** | **571** | **571** |
| **CMP Common Stock Equity** | | |
| Common stock ($5 par value, 80,000,000 shares authorized and 31,211,471 shares outstanding at December 31, 2024 and 2023) | 156,057 | 156,057 |
| Additional paid-in capital | 1,326,538 | 1,202,132 |
| Retained earnings | 1,198,609 | 1,020,633 |
| Accumulated other comprehensive loss | (2,891) | (3,057) |
| **Total CMP Common Stock Equity** | **2,678,313** | **2,375,765** |
| Noncontrolling interest | 34,276 | 41,732 |
| **Total Equity** | **2,712,589** | **2,417,497** |
| **Total Liabilities and Equity** | **$ 6,352,510** | **$ 5,919,274** |

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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Cash Flow from Operating Activities:** | | |
| **Net income** | **$ 181,414** | **$ 171,892** |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 138,014 | 131,383 |
| Regulatory assets/liabilities amortization | 58,519 | 56,415 |
| Regulatory assets/liabilities carrying cost | (17,239) | (1,261) |
| Amortization of debt issuance costs | 692 | 608 |
| Deferred taxes | 26,490 | 25,119 |
| Pension cost | (4,312) | (2,651) |
| Stock-based compensation | 877 | 99 |
| Gain on disposal of assets | (407) | (458) |
| Other non-cash items | (6,576) | (5,170) |
| **Changes in operating assets and liabilities:** | | |
| Accounts receivable, from affiliates, and unbilled revenues | (10,861) | (41,609) |
| Inventories | (3,585) | (28,363) |
| Accounts payable, to affiliates, and accrued liabilities | (115,429) | 107,753 |
| Taxes accrued | 18,114 | 10,024 |
| Other assets/liabilities | 55,758 | 42,141 |
| Regulatory assets/liabilities | (335,994) | (312,259) |
| **Net Cash (Used in) Provided by Operating Activities** | **(14,525)** | **153,663** |
| **Cash Flow from Investing Activities:** | | |
| Utility plant additions | (410,922) | (366,634) |
| Contributions in aid of construction | 68,118 | 50,134 |
| Notes receivable from affiliates | 5 | (12) |
| Proceeds from sale of utility plant | 416 | 4,319 |
| **Net Cash Used in Investing Activities** | **(342,383)** | **(312,193)** |
| **Cash Flow from Financing Activities:** | | |
| Non-current note issuance | 174,019 | 124,285 |
| Payments for finance leases | (97) | (14) |
| Notes payable to affiliates | 38,000 | 8,400 |
| Capital contribution | 125,000 | 175,000 |
| Distributions to noncontrolling interest | (10,860) | — |
| Dividends paid | (34) | (125,034) |
| **Net Cash Provided by Financing Activities** | **326,028** | **182,637** |
| **Net (Decrease) Increase in Cash and Cash Equivalents** | **(30,880)** | **24,107** |
| **Cash and Cash Equivalents, Beginning of Year** | **52,570** | **28,463** |
| **Cash and Cash Equivalents, End of Year** | **$ 21,690** | **$ 52,570** |

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 | Noncontrolling Interest | Total Common Stock Equity |
|---|---|---|---|---|---|---|---|---|
| **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** |
| Net income | — | — | — | 178,010 | — | 178,010 | 3,404 | 181,414 |
| Other comprehensive income, net of tax | — | — | — | — | 166 | 166 | — | 166 |
| Comprehensive income | | | | | | | | 181,580 |
| Stock-based compensation | — | — | (594) | — | — | (594) | — | (594) |
| Capital contribution from parent | — | — | 125,000 | — | — | 125,000 | — | 125,000 |
| Preferred stock dividends | — | — | — | (34) | — | (34) | — | (34) |
| Distributions to noncontrolling interest | — | — | — | — | — | — | (10,860) | (10,860) |
| **Balances, December 31, 2024** | **31,211,471** | **$ 156,057** | **$ 1,326,538** | **$1,198,609** | **$ (2,891)** | **$ 2,678,313** | **$ 34,276** | **$ 2,712,589** |

(*) 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 672,700 customers as of December 31, 2024, 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 a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Agreement and Plan of Merger:*** On May 17, 2024, AGR entered into an Agreement and Plan of Merger (the Merger Agreement) with Iberdrola and Arizona Merger Sub, Inc (Merger Sub). As a result of the consummation of the Merger on December 23, 2024 (closing date), Merger Sub merged with and into Avangrid (the Merger), with Avangrid continuing as the surviving corporation and a wholly-owned subsidiary of Iberdrola. On the closing date, each share of common stock issued and outstanding immediately prior to the closing date (other than common stock owned by the Merger, Merger Sub or any other direct or indirect wholly owned Subsidiary of the Merger, and in each case not held on behalf of the third parties (collectively, the Excluded Shares)) was converted into a right to receive $35.75 per share of common stock in cash, without interest.

On the closing date, (i) all shares of common stock ceased to be outstanding, were cancelled and ceased to exist and (ii) each Excluded Share ceased to be outstanding and was cancelled without payment of any consideration and ceased to exist. As a result of the consummation of the Merger on December 23, 2024, Iberdrola became the direct owner of 100 shares of common stock of Avangrid which represents the only outstanding capital of the Company. On the closing date, the New York Stock Exchange (NYSE) filed with the Securities and Exchange Commission (the SEC) a notification of removal from listing on Form 25 in order to delist the common stock from the NYSE and deregister the common stock under Section 12(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Following the effectiveness of the Form 25, on January 2, 2025, Avangrid filed with the SEC a Form 15 requesting the termination of registration of the common stock under Section 12(g) of the Exchange Act and the suspension of reporting obligations under Section 13 and 15(d) of the Exchange Act with respect to the common stock.

***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% of average depreciable property for both 2024 and 2023. 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 $199.5 million as of December 31, 2024, and $197.3 million as of December 31, 2023. Depreciation expense was $126.5 million in 2024 and $122.1 million in 2023. Amortization of capitalized software was $11.5 million in 2024 and $9.3 million in 2023, 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) | 2024 | 2023 |
|---|---|---|---|
| (Thousands) | | | |
| Electric | | | |
| Transmission | 4-70 | $ 3,007,765 | $ 2,864,360 |
| Distribution | 5-75 | 2,131,727 | 1,971,837 |
| Vehicles | 4-10 | 84,505 | 79,545 |
| Other | 4-50 | 593,313 | 551,058 |
| **Total Utility Plant in Service** | | **5,817,310** | **5,466,800** |
| Total accumulated depreciation | | (1,701,598) | (1,588,777) |
| **Total Net Utility Plant in Service** | | **4,115,712** | **3,878,023** |
| Construction work in progress | | 350,737 | 317,707 |
| **Total Utility Plant** | | **$ 4,466,449** | **$ 4,195,730** |

***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) | | 2024 | | 2023 |
|---|---|---|---|---|
| **Cash paid (refunded) during the year ended December 31:** | | | | |
| Interest, net of amounts capitalized | $ | 60,243 | $ | 47,418 |
| Income taxes refunded, net | $ | (11,742) | $ | (13,920) |

Of the income taxes (refunded) paid, ($15.5) million was refunded by AGR under the tax sharing agreement, partially offset by $3.8 million paid to the IRS. Interest capitalized was $7.8 million in 2024 and $5.9 million in 2023. Accrued liabilities for utility plant additions were $111.6 million and $53.2 million as of December 31, 2024 and 2023, 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 $52.0 million for 2024 and $45.3 million for 2023, and are shown net of an allowance for credit losses at December 31 of $15.1 million for 2024 and $14.7 million for 2023. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $7.6 million in 2024 and $5.1 million in 2023.

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 $5.8 million for 2024 and $7.0 million for 2023. DPA receivable balances at December 31 were $18.2 million for 2024 and $24.0 million for 2023.

***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, 2024 and 2023 consisted of:

| (Thousands) | Government grants | | Total | |
|---|---|---|---|---|
| **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** |
| Disposals | | — | | — |
| Recognized in income | | (4,004) | | (4,004) |
| **As of December 31, 2024** | **$** | **22,659** | **$** | **22,659** |

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, 2024 and 2023.

***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 carrying amount of ARO, including our conditional ARO, totaled $1.0 million at both December 31, 2024 and 2023 and is recorded in Other Non-current Liabilities on our consolidated balance sheets. There were no changes in ARO balances, including conditional ARO, for the years ended December 31, 2024 and 2023.

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 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 payable balance due to AGR at December 31, 2024 was $13.8 million. The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2023 was $3.4 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 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, 2024 and 2023.

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, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2024 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 standard is required to be adopted by private entities for the annual periods beginning after December 15, 2025. Early adoption is permitted. The two primary enhancements relate to disaggregation of the annual effective tax rate reconciliation and income taxes paid disclosures. 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 61% of our employees are covered by a collective bargaining agreement. All collective bargaining agreements 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 $32.8 million as of December 31, 2024, which has not changed since December 31, 2023, 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. On October 17, 2024, FERC issued its order on remand in the MISO ROE complaint proceedings. In this order, FERC reduced the MISO transmission owners' base ROE to 9.98% by eliminating the risk premium model from the ROE calculation, consistent with the DC Circuit's remand, and affirmed the refunds ordered in Opinion 569 (which were not addressed on appeal by the DC Circuit). On November 13, 2024, the NETOs submitted a supplemental brief into the NETO ROE case. The supplemental brief primarily addresses distinctions between the MISO transmission owners' and the NETOs' ROE cases. We cannot predict the potential impact that 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

On August 11, 2022, CMP filed a three year rate plan, with adjustments to the distribution revenue requirement in each year. On June 6, 2023, the MPUC approved 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. An increase occurred on January 1, 2024 and July 1, 2024. The last increase will occur on 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.

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 (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 Megawatt (MW) Rollins wind farm. Pursuant to a MPUC Order dated August 27, 2013, CMP entered into a 20-year fixed rate agreement with Athens Energy, LLC (formerly Maine Wood Pellets), a 7.1 MW wood-fired biomass cogeneration facility. Pursuant to a MPUC Order dated September 22, 2016, CMP entered into a 20-year fixed rate agreement with Georges River Energy, a 7.5 MW wood-fired biomass cogeneration facility. Pursuant to a MPUC Order dated August 3, 2017, CMP entered into a 20-year fixed rate agreement with Pittsfield Solar, 9.9 MW photovoltaic facility. 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 seven Dirigo solar facilities throughout CMP's service territory. Five of the seven facilities have achieved commercial operation totaling 33.37 MW. The two that have not achieved commercial operation total 9.98 MW. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with New England Aqua Ventus (formerly Maine Aqua Ventus I GP LLC) to purchase capacity and energy from an off-shore wind farm under development near Monhegan Island, Maine. This project has not achieved commercial operation. Pursuant to Maine law, the MPUC conducted two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%. Through contracts approved in December 2020 (Tranche 1), CMP was ordered to execute 13 contracts, of which eight have been terminated. Of the five contracts remaining, two have achieved commercial operation totaling 43.5 MW. The three that have not achieved commercial operation total 50.5 MW. In October 2021, CMP executed contracts with six additional facilities (Tranche 2), of which three have since terminated. Of the three contracts remaining, one has achieved commercial operation with 132 MW. The two that have not achieved commercial operation total 95 MW. Each of the Tranche 1 and Tranche 2 contracts 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 periodic auctions of the purchased output to wholesale buyers in the New England regional market, or through a sale to a third party for the RECs. Under Maine law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under Maine law, and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

**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 $271.1 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

Regulatory assets at December 31, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Asset retirement obligation | $ 965 | $ 965 |
| Deferred meter replacement costs | 17,067 | 19,059 |
| Energy efficiency programs | 3,306 | 281 |
| Environmental remediation costs | — | 361 |
| Federal tax depreciation normalization adjustment | 12,215 | 12,651 |
| Non-bypassable charges (stranded costs) | 86,324 | 88,476 |
| Pension and other post retirement benefits | 98,313 | 100,545 |
| Pension and other post retirement benefits cost deferrals | 11,018 | 11,606 |
| Revenue decoupling mechanism | 4,467 | — |
| Storm costs | 363,014 | 260,721 |
| Transmission revenue reconciliation mechanism | 68,911 | 250 |
| Unamortized losses on reacquired debt | 26 | 90 |
| Unfunded future income taxes | 244,849 | 227,570 |
| Other | 7,553 | 8,794 |
| **Total regulatory assets** | **918,028** | **731,369** |
| Less: current portion | 278,267 | 153,887 |
| **Total non-current regulatory assets** | **$ 639,761** | **$ 577,482** |

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.

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. 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 $363.0 million at December 31, 2024 and $260.7 million at December 31, 2023.

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, 2024 and 2023 consisted of:

| **As of December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Accrued removal obligations | $ 17,184 | $ 25,965 |
| Environmental remediation costs | 962 | 1,350 |
| Rate refund - FERC ROE proceeding | 32,757 | 30,114 |
| Revenue decoupling mechanism | — | 7,474 |
| Tax Act - remeasurement | 231,180 | 263,608 |
| Transmission revenue reconciliation mechanism | 5,990 | 56,575 |
| Other | 2,160 | 2,961 |
| **Total regulatory liabilities** | **290,233** | **388,047** |
| Less: current portion | 10,054 | 80,048 |
| **Total non-current regulatory liabilities** | **$ 280,179** | **$ 307,999** |

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

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

Rate refund - FERC ROE proceedings: see Note 2.

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

Tax Act – remeasurement 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, 2024 and 2023 are as follows:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Regulated operations – electricity | $ 1,165,913 | $ 1,050,617 |
| Other (a) | 36,871 | 25,221 |
| **Revenue from contracts with customers** | **1,202,784** | **1,075,838** |
| Leasing revenue | 1,583 | 1,551 |
| Alternative revenue programs | 51,375 | 26,822 |
| Other revenue | 19,130 | 23,170 |
| **Total operating revenues** | **$ 1,274,872** | **$ 1,127,381** |

(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 2024 and 2023 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2024 or 2023 that required us to update the assessment.

The carrying amount of goodwill was $324.9 million at both December 31, 2024 and 2023, with no accumulated impairment losses and no changes during 2024 and 2023.

## Note 6. Income Taxes

Current and deferred taxes charged to expense (benefit) for the years ended December 31, 2024 and 2023 consisted of:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| **Current** | | |
| Federal | $ 7,211 | $ (4,502) |
| State | (1,605) | 509 |
| **Current taxes charged to expense (benefit)** | **5,606** | **(3,993)** |
| **Deferred** | | |
| Federal | (301) | 16,197 |
| State | 26,791 | 8,922 |
| **Deferred taxes charged to expense** | **26,490** | **25,119** |
| **Total Income Tax Expense** | **$ 32,096** | **$ 21,126** |

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, 2024 and 2023 consisted of:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Tax expense at federal statutory rate | $ 44,837 | $ 40,534 |
| Property related flow through | (9,379) | (19,313) |
| State tax expense, net of federal benefit | 19,967 | 7,450 |
| Excess ADIT amortization | (10,255) | (7,973) |
| Excess ADIT remeasurement | (13,107) | — |
| Other, net | 33 | 428 |
| **Total Income Tax Expense** | **$ 32,096** | **$ 21,126** |

Income tax expense for the year ended December 31, 2024 was $12.7 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 15.0%. In 2024, the IRS issued private letter rulings (“PLRs”) 20242002, 20242003, and 20242004 to a non-affiliate. Within these rulings the IRS held that the normalization rules do not permit a utility’s net operating loss carryforward (“NOL”) Deferred Tax Asset (related to certain depreciation differences) to be reduced by intercompany tax allocation payments. In response, CMP analyzed its federal NOLs as of 12/31/2017 and reduced its excess ADIT deferred tax liability by $13.1 million to comply with the IRS rulings.

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 ADIT amortization and property related flow through, partially offset by state taxes. This resulted in an effective tax rate of 10.9%.

Deferred tax assets and liabilities as of December 31, 2024 and 2023 consisted of:

| **December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| **Non-current Deferred Income Tax Liabilities (Assets)** | | |
| Property related | $ 796,452 | $ 756,028 |
| Unfunded future income taxes | 63,407 | 51,831 |
| Pension and other postretirement benefits | 14,544 | 14,151 |
| Regulatory liability due to "Tax Cuts and Jobs Act" | (64,844) | (73,955) |
| Federal and state tax credits | (15,605) | — |
| Federal and state NOL's | (75,670) | (42,880) |
| Storm costs | 101,842 | 73,145 |
| Other | 30,531 | (4,670) |
| **Total Non-current Deferred Income Tax Liabilities** | **$ 850,657** | **$ 773,650** |
| Deferred tax assets | $ 156,119 | $ 121,505 |
| Deferred tax liabilities | 1,006,776 | 895,155 |
| **Net Accumulated Deferred Income Tax Liabilities** | **$ 850,657** | **$ 773,650** |

CMP had gross federal net operating losses of $259.3 million and gross Maine state net operating losses of $381.1 million as of December 31, 2024. CMP had gross federal net operating losses of $147.6 million and gross Maine state net operating losses of $293.3 million as of December 31, 2023.

CMP had $15.6 million of CAMT credit carryforward as of December 31, 2024, which will be available in future periods to offset regular federal income tax that exceeds CAMT. CMP had no CAMT credit carryforward outstanding at December 31, 2023.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2024 and 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, 2024 and 2023 consisted of:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| **Beginning Balance** | $ 8,989 | $ 12,241 |
| Reduction for tax positions related to prior years | (2,883) | (3,252) |
| **Ending Balance** | **$ 6,106** | **$ 8,989** |

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, 2024 or 2023.

### Note 7. Non-current Debt

Long-term debt as of December 31, 2024 and 2023 consisted of:

| **As of December 31,** | | **2024** | | **2023** | |
|---|---|---|---|---|---|
| **(Thousands, except interest rates)** | **Maturity Dates** | **Balances** | **Interest Rates** | **Balances** | **Interest Rates** |
| First mortgage bonds (a) | 2025-2052 | $ 1,450,000 | 1.87%-6.04% | $ 1,275,000 | 1.87%-6.04% |
| Senior unsecured notes | 2025-2037 | 140,000 | 5.375%-6.40% | 140,000 | 5.375%-6.40% |
| Unamortized debt issuance costs and discount | | (5,642) | | (4,759) | |
| **Total Debt** | | **1,584,358** | | **1,410,241** | |
| Less: debt due within one year, included in current liabilities | | 79,373 | | — | |
| **Total Non-current Debt** | | **$ 1,504,985** | | **$ 1,410,241** | |

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

On November 20, 2024, CMP issued $87 million aggregate principal amount of Green First Mortgage Bonds maturing in 2036 at an interest rate of 5.31% and $88 million aggregate principal amount of Green First Mortgage Bonds maturing in 2039 at an interest rate of 5.41%.

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%.

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

| **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
|---|---|---|---|---|---|
| **(Thousands)** | | | | | |
| $ 79,373 | $ 80,000 | $ — | $ 60,000 | $ 55,000 | $ 274,373 |

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2024 and 2023.

### Note 8. Bank Loans and Other Borrowings

CMP had $92.4 million of notes payable at December 31, 2024 and $54.4 million at December 31, 2023. 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 $92.4 million outstanding under this agreement at December 31, 2024 and no debt outstanding under this agreement at December 31, 2023.

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 no debt outstanding under this agreement at December 31, 2024 and $54.4 million outstanding under this agreement at December 31, 2023.

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. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates. 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, 2024 and 2023.

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, 2024. We are not in default as of December 31, 2024.

## 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, 2024 and 2023, our redeemable preferred stock was:

| Series | Par Value per Share | Redemption Price per Share | Shares Authorized and Outstanding(a) | Amount (Thousands) 2024 | 2023 |
|---|---|---|---|---|---|
| CMP, 6% Non-callable | $ 100 | $ — | 5,713 | $ 571 | $ 571 |
| **Total** | | | | **$ 571** | **$ 571** |

[(a)] At December 31, 2024 and 2023, 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 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 34 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, | 2024 | 2023 |
|---|---|---|
| **(Thousands)** | | |
| **Lease cost** | | |
| Finance lease cost | | |
| Amortization of right-of-use assets | $ 240 | $ 293 |
| Interest on lease liabilities | — | 1 |
| Total finance lease cost | 240 | 294 |
| Operating lease cost | 1,299 | 1,577 |
| Short-term lease cost | 46 | 76 |
| Variable lease cost | 40 | 39 |
| **Total lease cost** | **$ 1,625** | **$ 1,986** |

Balance sheet and other information for the years ended December 31, 2024 and 2023 was as follows:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except lease term and discount rate) | | |
| **Operating Leases** | | |
| Operating lease right-of-use assets | $ 15,958 | $ 14,374 |
| | | |
| Operating lease liabilities, current | 1,104 | 1,117 |
| Operating lease liabilities, long-term | 16,741 | 14,764 |
| Total operating lease liabilities | $ 17,845 | $ 15,881 |
| | | |
| **Finance Leases** | | |
| Other assets | $ 3,232 | $ 3,471 |
| | | |
| Other current liabilities | 5 | 13 |
| Other non-current liabilities | (85) | 3 |
| Total finance lease liabilities | $ (80) | $ 16 |
| | | |
| **Weighted-average Remaining Lease Term (years)** | | |
| Finance leases | 0.33 | 1.33 |
| Operating leases | 14.31 | 16.41 |
| **Weighted-average Discount Rate** | | |
| Finance leases | 3.47 % | 3.47 % |
| Operating leases | 4.09 % | 3.97 % |

For the years ended December 31, 2024 and 2023, supplemental cash flow information related to leases was as follows:

| For the Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash flows from operating leases | $ 1,665 | $ 1,493 |
| Operating cash flows from finance leases | $ — | $ 1 |
| Financing cash flows from finance leases | $ 97 | $ 14 |
| | | |
| Right-of-use assets obtained in exchange for lease obligations: | | |
| Finance leases | $ — | $ — |
| Operating leases | $ 3,150 | $ 505 |

As of December 31, 2024, maturities of lease liabilities were as follows:

| (Thousands) | Finance Leases | Operating Leases |
|---|---|---|
| **Year ending December 31,** | | |
| 2025 | $ (80) | $ 2,274 |
| 2026 | — | 2,263 |
| 2027 | — | 1,696 |
| 2028 | — | 1,699 |
| 2029 | — | 1,693 |
| Thereafter | — | 14,774 |
| **Total lease payments** | **(80)** | **24,399** |
| Less: imputed interest | — | (6,554) |
| **Total** | **$ (80)** | **$ 17,845** |

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

## Note 11. Commitments and Contingent Liabilities

### Power purchase contracts including non-utility generator

We recognized expense of approximately $29.7 million for non-utility generator power in 2024 and $28.2 million in 2023 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, one site is included in Maine's Uncontrolled Sites Program (MUSP), one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and one of the sites is 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 $1.4 million related to the five sites at December 31, 2024.

We have recorded an estimated liability of $3.7 million at December 31, 2024, 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. We have one additional site subject to Maine's Waste Management Program with a recorded estimated liability of $0.2 million at December 31, 2024 . It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate the nine total sites ranges from $4.3 million to $11.2 million as of December 31, 2024. 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, 2024. 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 at both December 31, 2024 and 2023. We recorded a corresponding regulatory asset because we expect to recover the net costs in rates.

**Keddy Mill Superfund Site**

On September 30, 2024, CMP received a special notice letter pursuant to Section 122(e) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) from the United States Department of Environmental Protection Agency related to contamination at the Keddy Mill Superfund Site in Windham, Maine that occurred in the 1960s and 1970s. The site had previously been owned by a CMP affiliate between 1941 and 1945. The letter notifies CMP of potential liability with respect to the site, informs CMP of planned remediation activities, and invites CMP to perform or finance those remediation activities. We are evaluating the allegations of liability and cannot predict the outcome of this matter.

Our environmental liabilities are recorded on an undiscounted basis and are expected to be paid through the year 2062.

**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.

The effect of hedging instruments on OCI and income for the years ended December 31, 2024 and 2023, 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) | | | | |
| **2024** | | | | |
| Interest rate contracts | $ — | Interest expense | $ (181) | $ 70,443 |
| **Total** | **$ —** | | **$ (181)** | |
| | | | | |
| **2023** | | | | |
| Interest rate contracts | $ — | Interest expense | $ (181) | $ 66,121 |
| **Total** | **$ —** | | **$ (181)** | |

The amount in AOCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $1.8 million for 2024 and $1.9 million for 2023. For the year ended December 31, 2024, 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 2025.

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

The estimated fair value of debt amounted to $1,489 million and $1,348 million as of December 31, 2024 and 2023, 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.

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2024 and 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.

### Note 15. Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss for the years ended December 31, 2024 and 2023 consisted of:

| (Thousands) | Balance December 31, 2022 | 2023 Change | Balance December 31, 2023 | 2024 Change | Balance December 31, 2024 |
|---|---|---|---|---|---|
| Amortization of pension cost for nonqualified plans and current year actuarial gain, net of income tax expense of $11 for 2023 and $14 for 2024 | $ (1,672) | $ 29 | $ (1,643) | $ 36 | $ (1,607) |
| Unrealized gain on derivatives qualified as hedges: | | | | | |
| Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $51 for both 2023 and 2024 | | 130 | | 130 | |
| Net unrealized gain on derivatives qualified as hedges | (1,544) | 130 | (1,414) | 130 | (1,284) |
| **Accumulated Other Comprehensive Loss** | **$ (3,216)** | **$ 159** | **$ (3,057)** | **$ 166** | **$ (2,891)** |

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 $10.8 million for 2024 and $9.3 million for 2023.

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 $1.1 million and $1.2 million at December 31, 2024 and 2023, respectively.

**Qualified Retirement Benefit Plans**

Obligations and funded status as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Change in benefit obligation** | | | | |
| **Benefit obligation as of January 1,** | **$ 286,951** | **$ 273,954** | **$ 68,088** | **$ 60,789** |
| Service cost | 1,884 | 1,705 | 299 | 298 |
| Interest cost | 13,025 | 13,686 | 3,037 | 2,980 |
| Actuarial (gain) loss | (20,782) | 15,366 | (302) | 10,765 |
| Benefits paid | (22,153) | (17,760) | (7,753) | (6,744) |
| **Benefit obligation as of December 31,** | **$ 258,925** | **$ 286,951** | **$ 63,369** | **$ 68,088** |
| **Change in plan assets** | | | | |
| **Fair value of plan assets at January 1,** | **$ 264,412** | **$ 260,536** | **$ 13,032** | **$ 14,746** |
| Actual return on plan assets | (189) | 21,636 | 1,180 | 2,155 |
| Employer contributions | — | — | 884 | 2,875 |
| Benefits paid | (22,153) | (17,760) | (7,753) | (6,744) |
| **Fair value of plan assets at December 31,** | **$ 242,070** | **$ 264,412** | **$ 7,343** | **$ 13,032** |
| **Funded status at December 31,** | **$ (16,855)** | **$ (22,539)** | **$ (56,026)** | **$ (55,056)** |

During 2024, the pension obligation had an actuarial gain of $20.8 million. This gain was primarily driven by $20.8 million gain from increase in discount rates. During 2024, the postretirement benefit obligation had an actuarial gain of $0.3 million. This gain was primarily driven by $3.9 million gain from increase in discount rates and $0.1 million gain from changes in demographic assumptions offset by $3.7 million loss from assumption changes in health care trend rates.

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

Amounts recognized in the consolidated balance sheets as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Non-current liabilities | $ (16,855) | $ (22,539) | $ (56,026) | $ (55,056) |

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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **Years Ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Net loss | $ 92,343 | $ 93,715 | $ 5,970 | $ 6,830 |

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $253.3 million and $280.2 million as of December 31, 2024 and 2023, respectively. Our postretirement benefits were partially funded at December 31, 2024 and 2023.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2024 and 2023. 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,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Projected benefit obligation | $ 258,925 | $ 286,951 |
| Accumulated benefit obligation | $ 253,345 | $ 280,184 |
| Fair value of plan assets | $ 242,070 | $ 264,412 |

As of December 31, 2024 and 2023, 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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **For the years ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Net Periodic Benefit Cost:** | | | | |
| Service cost | $ 1,884 | $ 1,705 | $ 299 | $ 298 |
| Interest cost | 13,025 | 13,686 | 3,037 | 2,980 |
| Expected return on plan assets | (20,018) | (18,042) | (624) | (1,009) |
| Amortization of net loss | 797 | — | 2 | — |
| **Net Periodic Benefit Cost** | **$ (4,312)** | **$ (2,651)** | **$ 2,714** | **$ 2,269** |
| **Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:** | | | | |
| Net loss (gain) | $ (575) | $ 11,772 | $ (858) | $ 9,619 |
| Amortization of net loss | (797) | — | (2) | — |
| **Total Other Changes** | **(1,372)** | **11,772** | **$ (860)** | **9,619** |
| **Total Recognized** | **$ (5,684)** | **$ 9,121** | **$ 1,854** | **$ 11,888** |

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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| Discount rate | 5.49% | 4.75% | 5.33% | 4.65% |
| Rate of compensation increase | 3.00% for Union | 3.00% for Union | 3.00% for Unions | 3.00% for Union |
| Interest crediting rate | 3.63% | 3.52% | 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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **Years Ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| Discount rate | 4.75 % | 5.21 % | 4.65 % | 5.13 % |
| Expected long-term return on plan assets | 7.25 % | 6.00 % | 6.60 % | 6.84 % |
| Rate of compensation increase | 3.00% for Union | 3.00% for Union | 3.00% for Union | 3.00% 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, 2024 and 2023 consisted of:

| **As of December 31,** | **2024** | **2023** |
|---|---|---|
| Health care cost trend rate assumed for next year | 8.90% / 10.60% | 8.10% / 8.60% |
| 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 | 2039 / 2039 | 2031 / 2032 |

### 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 2025.

### 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, 2024 consisted of:

| | Pension Benefits | Postretirement Benefits | Medicare Act Subsidy Receipts |
|---|---|---|---|
| (Thousands) | | | |
| 2025 | $ 25,108 | $ 5,118 | $ 161 |
| 2026 | $ 23,825 | $ 5,113 | $ 171 |
| 2027 | $ 23,847 | $ 5,146 | $ 180 |
| 2028 | $ 23,409 | $ 5,107 | $ 196 |
| 2029 | $ 22,699 | $ 5,116 | $ 206 |
| 2030 - 2034 | $ 104,662 | $ 25,123 | $ 1,229 |

### 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, 2024, consisted of:

| As of December 31, 2024 | | Fair Value Measurements | | |
|---|---|---|---|---|
| (Thousands) | Total | Level 1 | Level 2 | Level 3 |
| **Asset Category** | | | | |
| Cash and cash equivalents | $ 10,175 | $ 257 | $ 9,918 | $ — |
| U.S. government securities | 30,105 | 30,105 | — | — |
| Common stocks | 5,700 | 5,700 | — | — |
| Registered investment companies | 8,417 | 8,417 | — | — |
| Corporate bonds | 86,263 | — | 86,263 | — |
| Common collective trusts | 70,517 | — | 70,517 | — |
| Other, principally annuity, fixed income | 426 | — | 426 | — |
| | **$ 211,603** | **$ 44,479** | **$ 167,124** | **$ —** |
| Other investments measured at net asset value | 30,467 | | | |
| **Total** | **$ 242,070** | | | |

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** | | | |

### 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, 2024, consisted of:

| **As of December 31, 2024** | | **Fair Value Measurements** | | |
|---|---|---|---|---|
| **(Thousands)** | **Total** | **Level 1** | **Level 2** | **Level 3** |
| **Asset Category** | | | | |
| Cash and cash equivalents | $ 818 | $ (1) | $ 819 | $ — |
| U.S. government securities | 41 | 41 | — | — |
| Common stocks | 118 | 118 | — | — |
| Registered investment companies | 4,193 | 4,193 | — | — |
| Corporate bonds | 687 | — | 687 | — |
| Common collective trusts | 855 | — | 855 | — |
| Other, principally annuity, fixed income | 4 | — | 4 | — |
| | **$ 6,716** | **$ 4,351** | **$ 2,365** | **$ —** |
| Other investments measured at net asset value | 627 | | | |
| **Total** | **$ 7,343** | | | |

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 | $ 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** | | | |

### 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 Iberdrola common stock as of both December 31, 2024 and 2023.

### Note 17. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2024 and 2023 consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Interest and dividends income | $ | 62 | $ | — |
| Allowance for funds used during construction | | 11,459 | | 10,983 |
| Carrying costs on regulatory assets | | 23,133 | | 12,268 |
| Equity earnings | | 67 | | 61 |
| Miscellaneous | | 3,090 | | 2,135 |
| **Total other income** | **$** | **37,811** | **$** | **25,447** |
| Pension non-service components | $ | 3,747 | $ | 2,166 |
| Miscellaneous | | (3,736) | | (3,445) |
| **Total other income (deductions), net** | **$** | **11** | **$** | **(1,279)** |

### 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 $57.4 million and $50.4 million for 2024 and 2023, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $9.9 million in 2024 and $8.5 million in 2023. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by CMP to AGR and its subsidiaries were approximately $8.7 million for 2024 and $7.0 million for 2023. 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 $39.6 million at December 31, 2024 and the balance of $41.4 million at December 31, 2023 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $25.5 million at December 31, 2024 and the balance of $2.4 million at December 31, 2023 is mostly receivable from NECEC.

Notes receivable from affiliates at December 31, 2024 and at December 31, 2023 of $0.2 million and $0.3 million, respectively, are from Avangrid, Inc.

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.

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 years ended December 31, 2024 and 2023, CMP has received $1.5 million and $0.8 million, respectively, in payments from NECEC Transmission LLC related to the Rate Relief Fund.

## Note 19. Subsequent Events

The company has performed a review of subsequent events through March 25, 2025, which is the date these consolidated financial statements were available to be issued.

# Connecticut Natural Gas Corporation
## Financial Statements
## As of and for the Years Ended December 31, 2024 and 2023

## Connecticut Natural Gas Corporation

### Index

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

## Independent Auditors' Report

The Stockholder 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, 2024 and 2023, 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, 2024 and 2023, 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 28, 2025

## Connecticut Natural Gas Corporation
## Statements of Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Operating Revenues** | $ | **419,988** | $ | **428,699** |
| **Operating Expenses** | | | | |
| Natural gas purchased | | 178,452 | | 194,191 |
| Operations and maintenance | | 103,795 | | 108,846 |
| Depreciation and amortization | | 51,169 | | 49,784 |
| Taxes other than income taxes, net | | 31,893 | | 32,492 |
| **Total Operating Expenses** | | **365,309** | | **385,313** |
| **Operating Income** | | **54,679** | | **43,386** |
| Other income | | 4,250 | | 2,822 |
| Other (deductions) income, net | | (699) | | 964 |
| Interest expense, net of capitalization | | (14,035) | | (9,732) |
| **Income Before Income Tax** | | **44,195** | | **37,440** |
| Income tax expense | | 10,863 | | 8,249 |
| **Net Income** | $ | **33,332** | $ | **29,191** |

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

## Connecticut Natural Gas Corporation
## Statements of Comprehensive Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Net Income** | $ | **33,332** | $ | **29,191** |
| **Other Comprehensive Income (Loss), Net of Tax** | | | | |
| Amortization of pension cost for nonqualified plans and current year actuarial gain (loss), net of income tax expense (benefit) of $17 for 2024 and ($22) for 2023 | | 46 | | (59) |
| **Total Other Comprehensive Income (Loss), Net of Tax** | | **46** | | **(59)** |
| **Comprehensive Income** | $ | **33,378** | $ | **29,132** |

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

## Connecticut Natural Gas Corporation
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 220 | $ 421 |
| Accounts receivable and unbilled revenues, net | 114,156 | 107,260 |
| Accounts receivable from affiliates | 482 | 154 |
| Notes receivable from affiliates | 21,400 | 26,600 |
| Gas in storage | 33,463 | 41,998 |
| Materials and supplies | 6,027 | 5,603 |
| Other current assets | 4,911 | 4,130 |
| Regulatory assets | 60,170 | 50,255 |
| **Total Current Assets** | **240,829** | **236,421** |
| Utility plant, at original cost | 1,339,327 | 1,271,264 |
| Less accumulated depreciation | (448,552) | (424,187) |
| **Net Utility Plant in Service** | **890,775** | **847,077** |
| Construction work in progress | 25,424 | 21,284 |
| **Total Utility Plant** | **916,199** | **868,361** |
| Operating lease right-of-use assets | 2,882 | 2,746 |
| Other property and investments | 683 | 727 |
| **Regulatory and Other Assets** | | |
| Regulatory assets | 79,741 | 75,711 |
| Goodwill | 79,341 | 79,341 |
| Other | 348 | 188 |
| **Total Regulatory and Other Assets** | **159,430** | **155,240** |
| **Total Assets** | **$ 1,320,023** | **$ 1,263,495** |

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

## Connecticut Natural Gas Corporation
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except share information) | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Accounts payable and accrued liabilities | 71,537 | 63,158 |
| Accounts payable to affiliates | 20,717 | 19,077 |
| Interest accrued | 2,674 | 2,674 |
| Taxes accrued | 15,228 | 8,702 |
| Operating lease liabilities | 508 | 429 |
| Regulatory liabilities | 9,528 | 5,386 |
| Other | 18,838 | 18,538 |
| **Total Current Liabilities** | **139,030** | **117,964** |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | 318,984 | 309,536 |
| **Other Non-current Liabilities** | | |
| Deferred income taxes | 60,544 | 56,111 |
| Pension and other postretirement | 50,691 | 62,813 |
| Operating lease liabilities | 2,653 | 2,364 |
| Asset retirement obligation | 5,981 | 6,140 |
| Other | 1,591 | 1,448 |
| **Total Regulatory and Other Liabilities** | **440,444** | **438,412** |
| Non-current debt | 244,085 | 243,923 |
| **Total Liabilities** | **823,559** | **800,299** |
| **Commitments and Contingencies** | | |
| **Preferred Stock** | **340** | **340** |
| **Common Stock Equity** | | |
| Common stock ($3.125 par value, 20,000,000 shares authorized and 10,634,436 shares outstanding at December 31, 2024 and 2023) | 33,233 | 33,233 |
| Additional paid-in capital | 396,675 | 396,758 |
| Retained earnings | 66,477 | 33,172 |
| Accumulated other comprehensive loss | (261) | (307) |
| **Total Common Stock Equity** | **496,124** | **462,856** |
| **Total Liabilities and Equity** | **$ 1,320,023** | **$ 1,263,495** |

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

## Connecticut Natural Gas Corporation
## Statements of Cash Flows

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Cash Flow from Operating Activities:** | | |
| **Net income** | **$ 33,332** | **$ 29,191** |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 51,169 | 49,784 |
| Regulatory assets/liabilities amortization | 14,030 | 12,087 |
| Regulatory assets/liabilities carrying cost | 1,193 | 87 |
| Amortization of debt issuance costs | 162 | 134 |
| Deferred taxes | 2,939 | 6,988 |
| Pension cost | (193) | 196 |
| Stock-based compensation | 10 | 24 |
| Accretion expenses | 316 | 322 |
| Gain on disposal of assets | (3) | (57) |
| Other non-cash items | 368 | 276 |
| **Changes in operating assets and liabilities:** | | |
| Accounts receivable, from affiliates, and unbilled revenues | (7,224) | 42,519 |
| Inventories | 8,111 | 12,011 |
| Accounts payable, to affiliates, and accrued liabilities | 13,498 | (43,928) |
| Taxes accrued | 6,527 | (4,463) |
| Other assets/liabilities | 6,794 | 14,035 |
| Regulatory assets/liabilities | (52,920) | (27,684) |
| **Net Cash Provided by Operating Activities** | **78,109** | **91,522** |
| **Cash Flow from Investing Activities:** | | |
| Capital expenditures | (85,886) | (62,638) |
| Contributions in aid of construction | 2,379 | 2,643 |
| Proceeds from sale of utility plant | 24 | 214 |
| Notes receivable from affiliates | 5,200 | (26,600) |
| **Net Cash Used in Investing Activities** | **(78,283)** | **(86,381)** |
| **Cash Flow from Financing Activities:** | | |
| Non-current debt issuance | — | 54,687 |
| Notes payable to affiliates | — | (25,450) |
| Dividends paid | (27) | (35,027) |
| **Net Cash Used in Financing Activities** | **(27)** | **(5,790)** |
| **Net Decrease in Cash and Cash Equivalents** | **(201)** | **(649)** |
| **Cash and Cash Equivalents, Beginning of Period** | **421** | **1,070** |
| **Cash and Cash Equivalents, End of Period** | **$ 220** | **$ 421** |

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, 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** |
| Net income | — | — | — | 33,332 | — | 33,332 |
| Other comprehensive income, net of tax | — | — | — | — | 46 | 46 |
| Comprehensive income | | | | | | 33,378 |
| Stock-based compensation | — | — | (83) | — | — | (83) |
| Preferred stock dividends | — | — | — | (27) | — | (27) |
| **Balances, December 31, 2024** | **10,634,436** | **$ 33,233** | **$ 396,675** | **$ 66,477** | **$ (261)** | **$ 496,124** |

(*) 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 188,400 customers as of December 31, 2024, 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. (AGR), which is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Agreement and Plan of Merger:*** On May 17, 2024, AGR entered into an Agreement and Plan of Merger (the Merger Agreement) with Iberdrola and Arizona Merger Sub, Inc (Merger Sub). As a result of the consummation of the Merger on December 23, 2024 (closing date), Merger Sub merged with and into Avangrid (the Merger), with Avangrid continuing as the surviving corporation and a wholly-owned subsidiary of Iberdrola. On the closing date, each share of common stock issued and outstanding immediately prior to the closing date (other than common stock owned by the Merger, Merger Sub or any other direct or indirect wholly-owned Subsidiary of the Merger, and in each case not held on behalf of the third parties (collectively, the Excluded Shares)) was converted into a right to receive $35.75 per share of common stock in cash, without interest.

On the closing date, (i) all shares of common stock ceased to be outstanding, were cancelled and ceased to exist and (ii) each Excluded Share ceased to be outstanding and was cancelled without payment of any consideration and ceased to exist. As a result of the consummation of the Merger on December 23, 2024, Iberdrola became the direct owner of 100 shares of common stock of Avangrid which represents the only outstanding capital of the Company. On the closing date, the New York Stock Exchange (NYSE) filed with the Securities and Exchange Commission (the SEC) a notification of removal from listing on Form 25 in order to delist the common stock from the NYSE and deregister the common stock under Section 12(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Following the effectiveness of the Form 25, on January 2, 2025, Avangrid filed with the SEC a Form 15 requesting the termination of registration of the common stock under Section 12(g) of the Exchange Act and the suspension of reporting obligations under Section 13 and 15(d) of the Exchange Act with respect to the common stock.

***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 3.7% and 3.8% of average depreciable property for 2024 and 2023. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 10 years. Depreciation expense was $48.3 million in 2024 and $47.1 million in 2023. Amortization of capitalized software was $2.9 million in 2024 and $2.7 million in 2023.

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)** | | **2024** | | **2023** |
|---|---|---|---|---|---|
| **(Thousands)** | | | | | |
| Gas distribution plant | 5-75 | $ | 1,181,534 | $ | 1,116,388 |
| Software | 3-10 | | 47,173 | | 46,002 |
| Land | | | 1,618 | | 1,618 |
| Building and improvements | 35-50 | | 40,717 | | 40,376 |
| Other plant | 45-90 | | 68,285 | | 66,880 |
| **Total Utility Plant in Service** | | | **1,339,327** | | **1,271,264** |
| Total accumulated depreciation | | | (448,552) | | (424,187) |
| **Total Net Utility Plant in Service** | | | **890,775** | | **847,077** |
| Construction work in progress | | | 25,424 | | 21,284 |
| **Total Utility Plant** | | **$** | **916,199** | **$** | **868,361** |

***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:

| | 2024 | 2023 |
|---|---|---|
| **(Thousands)** | | |
| **Cash paid during the year ended December 31:** | | |
| Interest, net of amounts capitalized | $ 12,170 | $ 8,840 |
| Income taxes paid, net | $ 673 | $ 3,340 |

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $0.3 million in 2024 and $0.4 million in 2023. Accrued liabilities for utility plant additions were $11.5 million and $14.9 million as of December 31, 2024 and 2023, 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 $35.8 million for 2024 and $30.6 million for 2023, and are shown net of an allowance for credit losses at December 31 of $5.9 million for 2024 and $6.0 million for 2023. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $6.8 million in 2024 and $8.5 million in 2023.

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, 2024 and 2023.

***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, 2024 and 2023.

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| ARO, beginning of year | $ 6,140 | $ 6,279 |
| Liabilities settled during the year | (475) | (461) |
| Accretion expenses | 316 | 322 |
| **ARO, end of year** | **$ 5,981** | **$ 6,140** |

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 $9.9 million and $2.8 million at December 31, 2024 and 2023, 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, 2024 and 2023.

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 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, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2024 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 standard is required to be adopted by private entities for the annual periods beginning after December 15, 2025. Early adoption is permitted. The two primary enhancements relate to disaggregation of the annual effective tax rate reconciliation and income taxes paid disclosures. 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) 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 77% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

**Note 2. Industry Regulation**

**Rates**

Utilities are entitled by Connecticut statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

In December, 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with rate increases of $9.9 million, $4.6 million and $5.2 million in 2019, 2020 and 2021, respectively. The new tariffs, which are based on an ROE of 9.30% and an equity ratio of 54% in 2019, 54.50% in 2020, and 55% in 2021, continued, among other things, two separate ratemaking mechanisms that reconcile actual revenue requirements related to CNG's cast iron and bare steel replacement program and system expansion as well as a revenue decoupling mechanism and CNG's earnings sharing mechanism whereby CNG is required to return to customers 50% of any earnings over the allowed ROE in a calendar year and tariff increases. Given the expiration of the rate plan, CNG has been operating under the 2019 approved rate schedules for the years ended December 31, 2023.

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.

On November 19, 2024, PURA released a final Decision, which decreased CNG's rates by $24.5 million. The Decision approved an allowed ROE of 9.15% and an equity ratio of 53%. The Decision maintained CNG's distribution management program, but instituted a cap of $26 million. The Decision also established a low-income discount rate along with revenue decoupling and earning sharing mechanisms. On December 19, 2024, CNG filed an appeal of the Decision in the Connecticut Superior Court. We cannot predict the outcome of this matter.

**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 $71.7 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

Regulatory assets at December 31, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Deferred purchased gas | $ 8,563 | $ 6,579 |
| Distribution integrity management program | 13,169 | — |
| Hardship programs | 3,197 | — |
| Pension and other postretirement benefit plan | 60,121 | 61,337 |
| Revenue decoupling mechanism | 29,882 | 26,524 |
| System expansion reconciliation | 8,333 | 9,535 |
| Unfunded future income taxes | 11,624 | 10,473 |
| Other | 5,022 | 11,518 |
| **Total regulatory assets** | **139,911** | **125,966** |
| Less: current portion | 60,170 | 50,255 |
| **Total non-current regulatory assets** | **$ 79,741** | **$ 75,711** |

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.

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.

Hardship programs represent customer accounts deferred for 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.

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 items such as rate case costs and Environmental Defense Fund legal fees.

Regulatory liabilities at December 31, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Asset removal costs | $ 282,088 | $ 265,552 |
| Asset retirement obligation | 10,642 | 10,514 |
| Hardship programs | — | 2,558 |
| Non-firm margin sharing credits | 16,682 | 17,107 |
| Rate credits | 3,750 | 5,000 |
| Tax reform | 12,519 | 12,845 |
| Other | 2,831 | 1,346 |
| **Total regulatory liabilities** | **328,512** | **314,922** |
| Less: current portion | 9,528 | 5,386 |
| **Total non-current regulatory liabilities** | **$ 318,984** | **$ 309,536** |

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.

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects. This balance is amortized through current 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 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 items such as energy efficiency programs and Geographic Information System (GIS) data conversion.

**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, 2024 and 2023 are as follows:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Regulated operations – natural gas | $ 396,624 | $ 406,904 |
| Other (a) | 2,240 | 910 |
| **Revenue from contracts with customers** | **398,864** | **407,814** |
| Alternative revenue programs | 21,510 | 19,712 |
| Other revenue | (386) | 1,173 |
| **Total operating revenues** | **$ 419,988** | **$ 428,699** |

(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 2024 and 2023 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2024 or 2023 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, 2024 and 2023, with no accumulated impairment losses and no changes during 2024 and 2023.

### Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2024 and 2023 consisted of:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| **Current** | | |
| Federal | $ 8,268 | $ 435 |
| State | (344) | 826 |
| **Current taxes charged to expense** | **7,924** | **1,261** |
| **Deferred** | | |
| Federal | 289 | 6,977 |
| State | 2,650 | 11 |
| **Deferred taxes charged to expense** | **2,939** | **6,988** |
| **Total Income Tax Expense** | **$ 10,863** | **$ 8,249** |

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, 2024 and 2023 consisted of:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Tax expense at federal statutory rate | $ 9,281 | $ 7,862 |
| State taxes, net of federal income tax | 1,821 | 661 |
| Other, net | (239) | (274) |
| **Total Income Tax Expense** | **$ 10,863** | **$ 8,249** |

Income tax expense for the year ended December 31, 2024 was $1.6 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 24.6%. 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 were partially offset by tax benefits from Excess ADIT amortization and AFUDC flow through adjustments. This resulted in an effective tax rate of 22.0%.

Deferred tax assets and liabilities as of December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Non-current Deferred Income Tax Liabilities (Assets)** | | | | |
| CT credit carryforward | $ | (13,872) | $ | (7,397) |
| Valuation allowance - State Credits | | 5,590 | | 4,139 |
| Deferred tax liability on 2017 Tax Act remeasurement | | (3,371) | | (3,459) |
| Property related | | 55,018 | | 51,294 |
| Unfunded future income taxes | | 3,040 | | 2,761 |
| Goodwill | | 6,665 | | 6,196 |
| Pension (net) | | 1,675 | | (240) |
| Other | | 5,799 | | 2,817 |
| **Total Non-current Deferred Income Tax Liabilities** | **$** | **60,544** | **$** | **56,111** |
| Deferred tax assets | $ | 17,243 | $ | 11,096 |
| Deferred tax liabilities | | 77,787 | | 67,207 |
| **Net Accumulated Deferred Income Tax Liabilities** | **$** | **60,544** | **$** | **56,111** |

As of December 31, 2024, CNG had a state net credit carry forward of $13.9 million and a net state net operating loss carry forward of $1.9 million. 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. CNG’s state tax credit carry forwards will begin to expire for the 2024 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, 2024, CNG has recorded a valuation allowance of $5.6 million against its CT tax credits. The company also recorded a regulatory asset of $6.5 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, 2023, CNG had recorded a valuation allowance on its state credit carryforwards of $4.1 million. 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.

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, 2024 and 2023, 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, 2024 or 2023.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2024 or 2023.

**Note 7. Non-current Debt**

Long-term debt as of December 31, 2024 and 2023 consisted of:

| As of December 31, | | 2024 | | 2023 | |
|---|---|---|---|---|---|
| (Thousands, except interest rates) | Maturity Dates | Balances | Interest Rates | Balances | Interest Rates |
| Senior unsecured debt | 2028-2049 | $ 245,000 | 2.02%-6.66% | $ 245,000 | 2.02%-6.66% |
| Unamortized debt issuance costs and discount | | (915) | | (1,077) | |
| **Total Debt** | | **244,085** | | **243,923** | |
| Less: debt due within one year, included in current liabilities | | — | | — | |
| **Total Non-current Debt** | | **$ 244,085** | | **$ 243,923** | |

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 and thereafter consist of:

| 2025 | 2026 | 2027 | 2028 | 2029 | 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, 2024 and 2023.

### Note 8. Bank Loans and Other Borrowings

CNG had no outstanding balance under this agreement at December 31, 2024 and December 31, 2023. 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, 2024 and December 31, 2023.

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, 2024 and December 31, 2023.

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. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates. 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, 2024 and 2023.

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 0.33 to 1.00 at December 31, 2024. We are not in default as of December 31, 2024.

## Note 9. Redeemable Preferred Stock

At December 31, 2024 and 2023, our redeemable preferred stock was:

| | | | | Amount (Thousands) | |
|---|---|---|---|---|---|
| **Series** | **Par Value per Share** | **Redemption Price per Share** | **Shares Authorized and Outstanding(1)** | **2024** | **2023** |
| CNG, 8% Non-callable | $ 3.125 | $ — | 108,706 | $ 340 | $ 340 |
| **Total** | | | | **$ 340** | **$ 340** |

(1) At December 31, 2024 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 8 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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Lease cost** | | |
| Operating lease cost | $ 1,133 | $ 11 |
| Short-term lease cost | 64 | 88 |
| Variable lease cost | 25 | 14 |
| **Total lease cost** | **$ 1,222** | **$ 113** |

Balance sheet and other information for the years ended December 31, 2024 and 2023 was as follows:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except lease term and discount rate) | | |
| **Operating Leases** | | |
| Operating lease right-of-use assets | $ 2,882 | $ 2,746 |
| | | |
| Operating lease liabilities, current | 508 | 429 |
| Operating lease liabilities, long-term | 2,653 | 2,364 |
| Total operating lease liabilities | **$ 3,161** | **$ 2,793** |
| | | |
| **Weighted-average Remaining Lease Term (years)** | | |
| Operating leases | 6.60 | 7.14 |
| **Weighted-average Discount Rate** | | |
| Operating leases | 4.89 % | 3.66 % |

For the years ended December 31, 2024 and 2023, supplemental cash flow information related to leases was as follows:

| For the Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash flows from operating leases | $ 503 | $ 410 |
| | | |
| Right-of-use assets obtained in exchange for lease obligations: | | |
| Operating leases | $ 726 | $ 689 |

As of December 31, 2024, maturities of lease liabilities were as follows:

| (Thousands) | | Operating Leases |
|---|---|---|
| **Year ending December 31,** | | |
| 2025 | $ | 576 |
| 2026 | | 459 |
| 2027 | | 454 |
| 2028 | | 451 |
| 2029 | | 443 |
| Thereafter | | 1,378 |
| **Total lease payments** | | **3,761** |
| Less: imputed interest | | (600) |
| **Total** | **$** | **3,161** |

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, 2024 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, 2024, CNG has determined that remediation of the property in Hartford is not probable and therefore no amounts have been reserved.

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

The estimated fair value of debt amounted to $237 million and $246 million as of December 31, 2024 and 2023, 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, 2024 and 2023 consist of:

| | | Fair Value Measurements at December 31, Using | | |
|---|---|---|---|---|
| **Description** | **Total** | **(Level 1)** | **(Level 2)** | **(Level 3)** |
| **(Thousands)** | | | | |
| **2024** | | | | |
| **Assets** | | | | |
| Noncurrent investments | $ 683 | $ 683 | $ — | $ — |
| **Total** | **$ 683** | **$ 683** | **$ —** | **$ —** |
| | | | | |
| **2023** | | | | |
| **Assets** | | | | |
| Noncurrent investments | $ 727 | $ 727 | $ — | $ — |
| **Total** | **$ 727** | **$ 727** | **$ —** | **$ —** |

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2024 and 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 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 $3.3 million for 2024 and $3.2 million for 2023.

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, 2024 and 2023.

### Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Change in benefit obligation** | | | | |
| **Benefit obligation as of January 1,** | **$ 210,074** | **$ 201,847** | **$ 20,198** | **$ 17,397** |
| Service cost | — | 282 | 84 | 62 |
| Interest cost | 9,608 | 10,120 | 908 | 853 |
| Actuarial (gain) loss | (11,695) | 15,529 | 1,058 | 3,755 |
| Benefits paid | (14,750) | (17,704) | (2,924) | (1,869) |
| **Benefit obligation as of December 31,** | **$ 193,237** | **$ 210,074** | **$ 19,324** | **$ 20,198** |
| **Change in plan assets** | | | | |
| **Fair value of plan assets at January 1,** | **$ 155,681** | **$ 154,490** | **$ 11,778** | **$ 11,325** |
| Actual return on plan assets | 4,135 | 18,895 | 269 | 453 |
| Employer contributions | 5,457 | — | 2,224 | 1,869 |
| Benefits paid | (14,750) | (17,704) | (2,924) | (1,869) |
| **Fair value of plan assets at December 31,** | **$ 150,523** | **$ 155,681** | **$ 11,347** | **$ 11,778** |
| **Funded status at December 31,** | **$ (42,714)** | **$ (54,393)** | **$ (7,977)** | **$ (8,420)** |

During 2024, the pension benefit obligation had an actuarial gain of $11.7 million, primarily due to $14.8 million gain from increase in discount rate. During 2024, the postretirement benefit obligation had an actuarial loss of $1.1 million. This loss was primarily driven by $1.4 million gain from increase in discount rates offset by $1.3 million loss from assumption changes in health care trend rates.

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 rates. 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.

Amounts recognized as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Non-current liabilities | $ (42,714) | $ (54,393) | $ (7,977) | $ (8,420) |

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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **Years Ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Net loss (gain) | $ 11,595 | $ 17,623 | $ 5,442 | $ 4,709 |

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $193.2 million and $210.1 million as of December 31, 2024 and 2023. Our postretirement benefits were partially funded at December 31, 2024 and 2023.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2024 and 2023. 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,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Projected benefit obligation | $ 193,237 | $ 210,074 |
| Accumulated benefit obligation | $ 193,237 | $ 210,074 |
| Fair value of plan assets | $ 150,523 | $ 155,681 |

As of December 31, 2024 and 2023, 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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **For the years ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Net Periodic Benefit Cost:** | | | | |
| Service cost | $ — | $ 282 | $ 84 | $ 62 |
| Interest cost | 9,608 | 10,120 | 908 | 853 |
| Expected return on plan assets | (10,513) | (10,283) | (414) | (447) |
| Amortization of net loss | 712 | 77 | 471 | 110 |
| **Net Periodic Benefit Cost** | **$ (193)** | **$ 196** | **$ 1,049** | **$ 578** |

| Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities: | | | | |
|---|---|---|---|---|
| Net (gain) loss | $ (5,316) | $ 6,917 | $ 1,204 | $ 3,749 |
| Amortization of net loss | (712) | (77) | (471) | (110) |
| **Total Other Changes** | **(6,028)** | **6,840** | **733** | **3,639** |
| **Total Recognized** | **$ (6,221)** | **$ 7,036** | **$ 1,782** | **$ 4,217** |

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, 2024 and 2023 consisted of:

| | **Pension Benefits** | | **Postretirement Benefits** | |
|---|---|---|---|---|
| | **2024** | **2023** | **2024** | **2023** |
| Discount rate | 5.49% | 4.75% | 5.41% | 4.69% |
| Rate of compensation increase | N/A | N/A | N/A | N/A |
| Interest crediting rate | 3.57% | 3.47% | 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, 2024 and 2023 consisted of:

| | **Pension Benefits** | | **Postretirement Benefits** | |
|---|---|---|---|---|
| **Years Ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| Discount rate | 4.75 % | 5.21 % | 4.69 % | 5.13 % |
| Expected long-term return on plan assets | 7.50 % | 7.50 % | 4.10 % | 3.95 % |
| Rate of compensation increase (Union/Non-Union) | N/A | N/A | 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, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| Health care cost trend rate assumed for next year | 8.90% / 10.60% | 8.10% / 8.60% |
| 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 | 2039 / 2039 | 2031 / 2032 |

### 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 $4.4 million to our pension plans during 2025. We do not expect to contribute to our other postretirement benefit plans during 2025.

### 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, 2024 consisted of:

| (Thousands) | Pension Benefits | Postretirement Benefits | Medicare Act Subsidy Receipts |
|---|---|---|---|
| 2025 | $ 17,542 | $ 1,597 | $ 136 |
| 2026 | $ 16,660 | $ 1,574 | $ 138 |
| 2027 | $ 16,380 | $ 1,522 | $ 143 |
| 2028 | $ 16,929 | $ 1,499 | $ 146 |
| 2029 | $ 16,599 | $ 1,576 | $ 31 |
| 2030 - 2034 | $ 77,890 | $ 7,461 | $ 162 |

### 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, 2024, consisted of:

| **As of December 31, 2024** | | Fair Value Measurements | | |
|---|---|---|---|---|
| **(Thousands)** | **Total** | **Level 1** | **Level 2** | **Level 3** |
| **Asset Category** | | | | |
| Cash and cash equivalents | $ 6,927 | $ 353 | $ 6,574 | $ — |
| U.S. government securities | 19,659 | 19,659 | — | — |
| Common stocks | 6,508 | 6,508 | — | — |
| Registered investment companies | 12,128 | 12,128 | — | — |
| Corporate bonds | 24,446 | — | 24,446 | — |
| Common collective trusts | 49,765 | — | 49,765 | — |
| Other, principally annuity, fixed income | 127 | — | 127 | — |
| | **$ 119,560** | **$ 38,648** | **$ 80,912** | **$ —** |
| Other investments measured at net asset value | 30,963 | | | |
| **Total** | **$ 150,523** | | | |

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** | | | |

### 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 23% 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, 2024, consisted of:

| As of December 31, 2024 | | Fair Value Measurements | | |
|---|---|---|---|---|
| (Thousands) | Total | Level 1 | Level 2 | Level 3 |
| **Asset Category** | | | | |
| Cash and cash equivalents | $ 347 | $ (1) | $ 348 | $ — |
| U.S. government securities | 37 | 37 | — | — |
| Common stocks | 124 | 124 | — | — |
| Registered investment companies | 223 | 223 | — | — |
| Corporate bonds | 618 | — | 618 | — |
| Common collective trusts | 900 | — | 900 | — |
| Other, principally annuity, fixed income | 8,555 | — | 8,555 | — |
| | **$ 10,804** | **$ 383** | **$ 10,421** | **$ —** |
| Other investments measured at net asset value | 543 | | | |
| **Total** | **$ 11,347** | | | |

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 | $ 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** | | | |

### 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 Iberdrola common stock as of both December 31, 2024 and 2023.

### Note 14. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2024 and 2023 consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Interest and dividends income | $ | 1,895 | $ | — |
| Allowance for funds used during construction | | 985 | | 2,026 |
| Carrying costs on regulatory assets | | 1,245 | | 753 |
| Miscellaneous | | 125 | | 43 |
| **Total other income** | **$** | **4,250** | **$** | **2,822** |
| Pension non-service components | $ | 1,651 | $ | 2,403 |
| Miscellaneous | | (2,350) | | (1,439) |
| **Total other (deductions) income, net** | **$** | **(699)** | **$** | **964** |

### 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 $26.2 million and $20.3 million for the years ended December 31, 2024 and 2023, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $1.5 million in 2024 and $0.9 million in 2023. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by CNG to AGR and its subsidiaries were approximately $7.0 million for 2024 and $4.7 million for 2023. 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 $20.7 million at December 31, 2024 and $19.1 million at December 31, 2023 is mostly payable to UIL Holdings Corporation. The balance in accounts receivable from affiliates of $0.5 million at December 31, 2024 and $0.2 million at December 31, 2023 is mostly receivable from SCG.

There were $21.4 million in notes receivable from CMP at December 31, 2024, $26.6 million from NYSEG and BGC at December 31, 2023. 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 28, 2025, 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, 2024 and 2023

## New York State Electric & Gas Corporation

### Index

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

# Independent Auditors' Report

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

*Opinion*

We have audited the financial statements of New York State Electric & Gas Corporation (the Company), which comprise the balance sheets as of December 31, 2024 and 2023, and the related statements of income, comprehensive income, changes in stockholder's 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, 2024 and 2023, 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 21, 2025

## New York State Electric & Gas Corporation
## Statements of Income

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Operating Revenues** | $ 2,373,591 | $ 2,196,936 |
| **Operating Expenses** | | |
| Electricity purchased | 577,004 | 513,155 |
| Natural gas purchased | 88,061 | 127,177 |
| Operations and maintenance | 968,758 | 907,062 |
| Depreciation and amortization | 230,310 | 208,969 |
| Taxes other than income taxes, net | 178,996 | 161,089 |
| **Total Operating Expenses** | **2,043,129** | **1,917,452** |
| **Operating Income** | **330,462** | **279,484** |
| Other income | 77,651 | 49,638 |
| Other (deductions) income, net | 7,283 | 13,628 |
| Interest expense, net of capitalization | (109,774) | (86,858) |
| **Income Before Income Tax** | **305,622** | **255,892** |
| Income tax expense | 61,560 | 43,657 |
| **Net Income** | $ **244,062** | $ **212,235** |

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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Net Income** | $ **244,062** | $ **212,235** |
| **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 | (108) | 24 |
| Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax | — | 227 |
| **Total Other Comprehensive Income (Loss), Net of Tax** | **(108)** | **251** |
| **Comprehensive Income** | $ **243,954** | $ **212,486** |

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

## New York State Electric & Gas Corporation
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| **(Thousands)** | | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 4,444 | $ 6,101 |
| Accounts receivable and unbilled revenues, net | 375,291 | 348,556 |
| Accounts receivable from affiliates | 2,409 | 4,900 |
| Notes receivable from affiliates | 41,300 | — |
| Fuel and natural gas in storage | 17,045 | 19,022 |
| Materials and supplies | 46,985 | 47,037 |
| Broker margin accounts | — | 12,039 |
| Derivative assets | 10,621 | — |
| Prepaid property taxes | 41,500 | 38,757 |
| Other current assets | 28,483 | 19,695 |
| Regulatory assets | 269,166 | 204,332 |
| **Total Current Assets** | **837,244** | **700,439** |
| Utility plant, at original cost | 9,328,326 | 8,528,387 |
| Less accumulated depreciation | (2,552,644) | (2,490,347) |
| **Net Utility Plant in Service** | **6,775,682** | **6,038,040** |
| Construction work in progress | 903,915 | 882,447 |
| **Total Utility Plant** | **7,679,597** | **6,920,487** |
| Operating lease right-of-use assets | 7,305 | 8,202 |
| Other property and investments | 9,316 | 8,779 |
| **Regulatory and Other Assets** | | |
| Regulatory assets | 1,314,623 | 1,050,289 |
| Other | 33,885 | 40,526 |
| **Total Regulatory and Other Assets** | **1,348,508** | **1,090,815** |
| **Total Assets** | **$ 9,881,970** | **$ 8,728,722** |

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

## New York State Electric & Gas Corporation
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except share information) | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Current portion of long-term debt | $ — | $ 9,603 |
| Notes payable to affiliates | — | 83,300 |
| Accounts payable and accrued liabilities | 635,943 | 565,373 |
| Accounts payable to affiliates | 54,229 | 120,564 |
| Interest accrued | 39,348 | 29,288 |
| Taxes accrued | 11,102 | 9,712 |
| Operating lease liabilities | 1,318 | 1,237 |
| Environmental remediation costs | 5,914 | 6,061 |
| Customer deposits | 11,342 | 13,858 |
| Regulatory liabilities | 64,233 | 75,587 |
| Other | 111,328 | 110,600 |
| **Total Current Liabilities** | **934,757** | **1,025,183** |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | 872,039 | 917,132 |
| **Other Non-current Liabilities** | | |
| Deferred income taxes | 975,293 | 853,843 |
| Pension and other postretirement | 73,144 | 119,885 |
| Operating lease liabilities | 7,167 | 8,034 |
| Asset retirement obligation | 10,767 | 11,078 |
| Environmental remediation costs | 51,108 | 53,233 |
| Other | 24,762 | 24,119 |
| **Total Regulatory and Other Liabilities** | **2,014,280** | **1,987,324** |
| Non-current debt | 3,398,466 | 2,875,190 |
| **Total Liabilities** | **6,347,503** | **5,887,697** |
| **Commitments and Contingencies** | | |
| **Common Stock Equity** | | |
| Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 64,508,477 shares outstanding at December 31, 2024 and 2023) | 430,057 | 430,057 |
| Additional paid-in capital | 2,378,630 | 1,929,142 |
| Retained earnings | 726,457 | 482,395 |
| Accumulated other comprehensive loss | (677) | (569) |
| **Total Common Stock Equity** | **3,534,467** | **2,841,025** |
| **Total Liabilities and Equity** | **$ 9,881,970** | **$ 8,728,722** |

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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Cash Flow from Operating Activities:** | | |
| **Net income** | **$ 244,062** | **$ 212,235** |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 230,310 | 208,969 |
| Regulatory assets/liabilities amortization | 64,274 | 6,029 |
| Regulatory assets/liabilities carrying cost | (27,031) | (7,899) |
| Amortization of debt issuance costs | 2,905 | 2,947 |
| Deferred taxes | 94,473 | 52,984 |
| Pension cost | (7,474) | (14,315) |
| Stock-based compensation | 547 | (15) |
| Accretion expenses | 582 | 596 |
| Gain from disposal of property | (196) | (759) |
| Other non-cash items | (62,476) | (74,446) |
| Changes in assets and liabilities | | |
| Accounts receivable, from affiliates, and unbilled revenues | (24,244) | 81,222 |
| Inventories | 2,029 | 22,512 |
| Accounts payable, to affiliates, and accrued liabilities | (17,752) | (96,732) |
| Taxes accrued | 1,390 | 7,334 |
| Other assets/liabilities | 80,625 | (46,256) |
| Regulatory assets/liabilities | (495,727) | (289,537) |
| **Net Cash Provided by Operating Activities** | **86,297** | **64,869** |
| **Cash Flow from Investing Activities:** | | |
| Capital expenditures | (964,490) | (838,955) |
| Contributions in aid of construction | 41,475 | 39,731 |
| Proceeds from sale of property, plant and equipment | 2,026 | 5,376 |
| Notes receivable from affiliates | (41,300) | — |
| **Net Cash Used in Investing Activities** | **(962,289)** | **(793,848)** |
| **Cash Flow from Financing Activities:** | | |
| Non-current debt issuance | 519,859 | 841,791 |
| Repayments of non-current debt | (12,000) | (300,000) |
| Payments of finance leases | (224) | (212) |
| Notes payable to affiliates | (83,300) | (6,500) |
| Capital contribution | 450,000 | 400,000 |
| Dividends paid | — | (200,000) |
| **Net Cash Provided by Financing Activities** | **874,335** | **735,079** |
| **Net (Decrease) Increase in Cash and Cash Equivalents** | **(1,657)** | **6,100** |
| **Cash and Cash Equivalents, Beginning of Year** | **6,101** | **1** |
| **Cash and Cash Equivalents, End of Year** | **$ 4,444** | **$ 6,101** |

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, 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** |
| Net income | — | — | — | 244,062 | — | 244,062 |
| Other comprehensive loss, net of tax | — | — | — | — | (108) | (108) |
| Comprehensive income | | | | | | 243,954 |
| Stock-based compensation | — | — | (512) | — | — | (512) |
| Capital contribution | — | — | 450,000 | — | — | 450,000 |
| **Balance, December 31, 2024** | **64,508,477** | **$ 430,057** | **$ 2,378,630** | **$ 726,457** | **$ (677)** | **$ 3,534,467** |

(*) 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 921,000 electricity and 271,000 natural gas customers as of December 31, 2024, 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 a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Agreement and Plan of Merger:*** On May 17, 2024, AGR entered into an Agreement and Plan of Merger (the Merger Agreement) with Iberdrola and Arizona Merger Sub, Inc (Merger Sub). As a result of the consummation of the Merger on December 23, 2024 (closing date), Merger Sub merged with and into Avangrid (the Merger), with Avangrid continuing as the surviving corporation and a wholly-owned subsidiary of Iberdrola. On the closing date, each share of common stock issued and outstanding immediately prior to the closing date (other than common stock owned by the Merger, Merger Sub or any other direct or indirect wholly owned Subsidiary of the Merger, and in each case not held on behalf of the third parties (collectively, the Excluded Shares)) was converted into a right to receive $35.75 per share of common stock in cash, without interest.

On the closing date, (i) all shares of common stock ceased to be outstanding, were cancelled and ceased to exist and (ii) each Excluded Share ceased to be outstanding and was cancelled without payment of any consideration and ceased to exist. As a result of the consummation of the Merger on December 23, 2024, Iberdrola became the direct owner of 100 shares of common stock of Avangrid which represents the only outstanding capital of the Company. On the closing date, the New York Stock Exchange (NYSE) filed with the Securities and Exchange Commission (the SEC) a notification of removal from listing on Form 25 in order to delist the common stock from the NYSE and deregister the common stock under Section 12(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Following the effectiveness of the Form 25, on January 2, 2025, Avangrid filed with the SEC a Form 15 requesting the termination of registration of the common stock under Section 12(g) of the Exchange Act and the suspension of reporting obligations under Section 13 and 15(d) of the Exchange Act with respect to the common stock.

***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.

## Notes to Financial Statements

***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 both 2024 and 2023. 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 $321.3 million as of December 31, 2024 and $314.8 million as of December 31, 2023. Depreciation expense was $214.8 million in 2024 and $193.9 million in 2023. Amortization of capitalized software was $15.5 million in 2024 and $15.0 million in 2023.

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:

**Notes to Financial Statements**

| Utility Plant | Estimated useful life range (years) | | 2024 | | 2023 |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| Electric | 2-80 | $ | 6,647,665 | $ | 6,021,282 |
| Natural Gas | 2-75 | | 1,444,527 | | 1,380,310 |
| Common | 7-70 | | 1,236,134 | | 1,126,795 |
| **Total Utility Plant in Service** | | | **9,328,326** | | **8,528,387** |
| Total accumulated depreciation | | | (2,552,644) | | (2,490,347) |
| **Total Net Utility Plant in Service** | | | **6,775,682** | | **6,038,040** |
| Construction work in progress | | | 903,915 | | 882,447 |
| **Total Utility Plant** | | **$** | **7,679,597** | **$** | **6,920,487** |

***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

## Notes to Financial Statements

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 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:

| | | 2024 | | 2023 |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Cash paid (refunded) during the years ended December 31:** | | | | |
| Interest, net of amounts capitalized | $ | 96,949 | $ | 73,048 |
| Income taxes refunded, net | $ | (27,329) | $ | (17,250) |

Of the income taxes refunded, substantially all was refunded by AGR under the tax sharing agreement. Interest capitalized was $20.5 million in 2024 and $16.9 million in 2023. Accrued liabilities for utility plant additions were $179.5 million and $151.5 million as of December 31, 2024 and 2023, 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 $115.4 million for 2024 and $101.4 million for 2023, and are shown net of an allowance for credit losses at December 31 of $68.6 million for 2024 and $62.8 million for 2023. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $55.1 million in 2024, including $0.8 million of arrears forgiveness balances. Credit loss expense was $62.1 million in 2023, including $19.3 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 $31.5 million for 2024 and $17.6 million for 2023. DPA receivable balances at December 31 were $52.3 million for 2024 and $39.1 million for 2023.

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

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

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

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

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

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

The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2024 and 2023 consisted of:

| **(Thousands)** | **Government grants** | **Total** |
|---|---|---|
| **As of December 31, 2022** | **$ 10,783** | **$ 10,783** |
| Disposals | — | — |
| Recognized in income | (291) | (291) |
| **As of December 31, 2023** | **$ 10,492** | **$ 10,492** |
| Disposals | — | — |
| Recognized in income | (291) | (291) |
| **As of December 31, 2024** | **$ 10,201** | **$ 10,201** |

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, 2024 and 2023.

***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, 2024 and 2023.

| **Years ended December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| ARO, beginning of year | $ | 11,078 | $ | 11,349 |
| Liabilities settled during the year | | (893) | | (867) |
| Accretion expense | | 582 | | 596 |
| **ARO, end of year** | **$** | **10,767** | **$** | **11,078** |

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.

***Post-employment and other employee benefits:*** We sponsor defined benefit pension plans that cover eligible 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. 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. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans 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 $4.1 million and $5.5 million at December 31, 2024 and 2023, 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, 2024 and 2023.

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 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, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2024 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 standard is required to be adopted by private entities for the annual periods beginning after December 15, 2025. Early adoption is permitted. The two primary enhancements relate to disaggregation of the annual effective tax rate reconciliation and income taxes paid disclosures. 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) 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 70% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire during 2025.

## 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.

**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. An Order was issued on April 18, 2024 approving the Companies’ filed tariff amendments on a permanent basis. 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 NYSEG's 2020 Rate Plan. Modifications to EAMs were approved by the Commission on October 12, 2023 in its Order approving NYSEG's 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. On January 16, 2024, 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. On May 16, 2024, the NYPSC issued an Order approving a statewide Solar for All program, effective December 1, 2025, whereby utilities would aggregate bill credits generated by participating CDG projects and distribute them among customers automatically enrolled in the utility's low-income energy affordability programs that are located in a disadvantaged community. Also on May 16, 2024, the NYPSC issued an Order that permits CDG projects to offer up to three distinct CDG savings rates to CDG subscribers beginning June 1, 2025.

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 November 16, 2023, the Commission issued its Order Approving Midpoint Review Whitepaper's Recommendations with Modifications. The Order increased the total budget to $1.243 billion for the statewide program (NYSEG and RG&E combined share is approximately $131 million).

- 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 has tariffs in effect to collect costs for the procurement of qualified energy storage assets. On June 20, 2024, the NYPSC issued an Order establishing an updated storage goal and deployment policy.

- On April 18, 2024 the NYPSC instituted a proceeding intended to transition New York to a more connected, affordable, resilient, and clean electric grid. During the proceeding, Public Service Commission staff will engage with stakeholders to develop a comprehensive New York Grid of the Future plan that establishes targets for the deployment of flexible resources such as virtual power plants and identifies the utility investments needed to enable the grid of the future. The NYPSC is commencing this proceeding to establish a clear set of needed grid capabilities, establish targets for deployment of those capabilities, identify required investments to effectuate those targets, and identify the anticipated customer benefits and savings achievable from meeting those targets. NYPSC Staff filed a Grid Flexibility Study on January 31, 2025 and will develop and file the first iteration of the "New York Grid of the Future Plan" (Plan) by February 28, 2025.

- On August 15, 2024, the NYPSC issued an Order Establishing Proactive Planning Proceeding. The Order directs utilities to develop and propose a framework for a process to proactively plan for electric vehicles and electrification, and to identify urgent projects that may need to be deployed before the planning process is completed. On December 13, 2024, the Joint Utilities filed a long-term proactive planning framework.

**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. The CSRA requires utilities to obtain authorization from the Commission prior to seeking recovery of a 100% construction work in progress (CWIP) incentive associated with CLCPA Phase 2 projects. In an April 19, 2024 Order, the Commission granted the Company's request for authorization to seek a 100% CWIP incentive for its CLCPA Phase 2 projects. On July 5, 2024, FERC conditionally accepted NYSEG's application for CWIP and the 100% Abandoned Plant incentive (Abandoned Plant), subject to further compliance, for projects that are subject to subsequent permitting approval by the NYPSC under Article VII of New York State's Public Service Law, effective July 8, 2024, and denied the application for CWIP and Abandoned Plant for projects not subject to Article VII permitting approval. NYSEG is assessing the July 5, 2024 FERC order and the impacts on the companies. On October 1, FERC ruled on NYSEG's request for clarification/rehearing. FERC confirmed that any projects that receive state siting approval orders that include the required reliability and/or congestion reduction determinations can qualify for incentives, not limited to the projects listed in the July order as Article VII projects. FERC denied clarification and rehearing to include CWIP in rate base prior to FERC's acceptance of the state siting orders.

### 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 $130.1 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

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 $39.0 million for the year ended December 31, 2024.

Regulatory assets at December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Asset retirement obligation | $ | 11,014 | $ | 11,303 |
| Electric supply reconciliation | | 17,632 | | 4,991 |
| Environmental remediation costs | | 50,516 | | 47,167 |
| Energy efficiency programs | | — | | 8,967 |
| Federal tax depreciation normalization adjustment | | 71,851 | | 75,627 |
| Low income programs | | 21,298 | | 12,701 |
| Low income arrears forgiveness | | 9,748 | | 24,066 |
| Make-whole provision | | 37,059 | | 63,342 |
| Pension and other post-retirement benefits | | 76,952 | | 99,656 |
| Pension and other post-retirement benefits cost deferrals | | 12,595 | | 16,559 |
| Rate adjustment mechanism | | 17,175 | | 15,734 |
| Rate change levelization | | 72,723 | | 38,572 |
| Revenue decoupling mechanism | | 28,008 | | 14,095 |
| Sales and use tax audit deferral | | 7,651 | | 9,269 |
| Storm costs | | 808,286 | | 529,811 |
| Unamortized loss on re-acquired debt | | 7,992 | | 9,686 |
| Uncollectible reserve | | 77,565 | | 61,661 |
| Unfunded future income taxes | | 28,669 | | 17,758 |
| Value distributed energy resource | | 35,553 | | 32,617 |
| Vegetation management | | 86,276 | | 69,859 |
| Other | | 105,226 | | 91,180 |
| **Total regulatory assets** | | **1,583,789** | | **1,254,621** |
| Less: current portion | | 269,166 | | 204,332 |
| **Total non-current regulatory assets** | **$** | **1,314,623** | **$** | **1,050,289** |

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

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

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

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.

## Notes to Financial Statements

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, 2023, 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 $808.3 million at December 31, 2024 and $529.8 million at December 31, 2023. 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, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Accrued removal obligation | $ | 392,255 | $ | 430,834 |
| Accumulated deferred investment tax credits | | 9,910 | | 10,554 |
| Debt rate reconciliation | | 5,430 | | 17,830 |
| Energy efficiency programs | | 561 | | — |
| Gas supply charge and deferred natural gas cost | | — | | 7,022 |
| Hedge gains | | 12,495 | | — |
| New York 2018 winter storm settlement | | 95 | | 160 |
| Non by-passable charges | | 3,163 | | 9,076 |
| Pension and other postretirement benefits | | 51,248 | | 37,088 |
| Pension and other postretirement benefits cost deferral | | 8,293 | | 11,330 |
| Property tax | | 5,137 | | 5,238 |
| Service quality performance mechanism | | 41,809 | | 38,717 |
| Tax Act remeasurement | | 340,018 | | 356,074 |
| Unfunded future income taxes | | 254 | | 1,076 |
| Other | | 65,604 | | 67,720 |
| **Total regulatory liabilities** | | **936,272** | | **992,719** |
| Less: current portion | | 64,233 | | 75,587 |
| **Total non-current regulatory liabilities** | **$** | **872,039** | **$** | **917,132** |

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.

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.

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

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.

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.

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.

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 $8.9 million at December 31, 2024 and $17.4 million at December 31, 2023, and are presented in "Other current liabilities" on our balance sheets. We recognized $20.9 million and $43.7 million as revenue during the years ended December 31, 2024 and 2023, 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, 2024 and 2023 are as follows:

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Regulated operations – electricity | $ 1,966,855 | $ 1,768,816 |
| Regulated operations – natural gas | 318,753 | 362,304 |
| Other(a) | 34,999 | 21,440 |
| **Revenue from contracts with customers** | **2,320,607** | **2,152,560** |
| Leasing revenue | 1,009 | 919 |
| Alternative revenue programs | 35,336 | 24,188 |
| Other revenue | 16,639 | 19,269 |
| **Total operating revenues** | **$ 2,373,591** | **$ 2,196,936** |

(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, 2024 and 2023 consisted of:

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Current | | |
| Federal | $ (32,675) | $ (8,990) |
| State | (238) | (337) |
| **Current taxes charged to benefit** | **(32,913)** | **(9,327)** |
| Deferred | | |
| Federal | 74,933 | 39,354 |
| State | 20,050 | 14,140 |
| **Deferred taxes charged to expense** | **94,983** | **53,494** |
| Investment tax credit adjustments | (510) | (510) |
| **Total Income Tax Expense** | **$ 61,560** | **$ 43,657** |

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, 2024 and 2023, respectively, consisted of:

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Tax expense at statutory rate | $ 64,181 | $ 53,737 |
| Equity AFUDC tax effects | (6,071) | (4,535) |
| Excess ADIT amortization | (11,872) | (16,354) |
| Investment tax credit amortization | (510) | (510) |
| State tax expense, net of federal benefit | 15,651 | 10,904 |
| Other, net | 181 | 415 |
| **Total Income Tax Expense** | **$ 61,560** | **$ 43,657** |

Income tax expense for the year ended December 31, 2024 was $2.6 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 20.1%. 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 ADIT amortization and AFUDC Equity tax effects, partially offset by state taxes. This resulted in an effective tax rate of 17.1%.

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, 2024 and 2023 consisted of:

| **December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Non-current Deferred Income Tax Liabilities (Assets)** | | | | |
| Property related | $ | 1,062,430 | $ | 957,039 |
| Storm costs | | 212,100 | | 138,998 |
| Pension and other post-retirement benefits | | (8,688) | | (11,074) |
| Power tax deferred income tax | | 18,854 | | 19,841 |
| Regulatory liability due to "Tax Cuts and Jobs Act" | | (89,227) | | (93,423) |
| Environmental | | (14,963) | | (15,556) |
| Federal and state NOL’s | | (308,191) | | (214,429) |
| Other | | 102,978 | | 72,447 |
| **Total Non-current Deferred Income Tax Liabilities** | **$** | **975,293** | **$** | **853,843** |
| Deferred tax assets | $ | 421,069 | $ | 334,482 |
| Deferred tax liabilities | | 1,396,362 | | 1,188,325 |
| **Net Accumulated Deferred Income Tax Liabilities** | **$** | **975,293** | **$** | **853,843** |

NYSEG has gross federal net operating losses of $1,051.8 million and gross NY state net operating losses of $1,685.2 million for the year ended December 31, 2024. NYSEG had gross federal net operating losses of $743 million and gross NY state net operating losses of $1,115.5 million for the year ended December 31, 2023.

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, 2024 and 2023 consisted of:

| **Years Ended December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| Balance as of January 1 | $ | 44,905 | $ | 44,978 |
| Reduction for tax positions related to prior years | | (73) | | (73) |
| **Balance as of December 31** | **$** | **44,832** | **$** | **44,905** |

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, 2024 and 2023.

## Note 6. Long-term Debt

Long-term debt as of December 31, 2024 and 2023 consisted of:

| As of December 31, | | 2024 | | 2023 | |
|---|---|---|---|---|---|
| (Thousands, except interest rates) | Maturity Dates | Balances | Interest Rates | Balances | Interest Rates |
| Senior unsecured debt | 2026-2052 | $ 2,975,000 | 1.95%-5.85% | $ 2,450,000 | 1.95%-5.85% |
| Unsecured pollution control notes – fixed | 2026-2034 | 441,210 | 1.40% - 4.00% | 453,210 | 1.40% - 4.00% |
| Unamortized debt issuance costs and discount | | (17,744) | | (18,417) | |
| **Total Debt** | | **$3,398,466** | | **$2,884,793** | |
| Less: debt due within one year, included in current liabilities | | — | | 9,603 | |
| **Total Non-current Debt** | | **$ 3,398,466** | | **$ 2,875,190** | |

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%.

On August 6, 2024, NYSEG issued $525 million aggregate principal amount of unsecured green public bond maturing in 2034 at an interest of 5.30%.

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

| 2025 | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| $— | $565,000 | $34,000 | $417,210 | $175,000 | $1,191,210 |

## Note 7. Bank Loans and Other Borrowings

NYSEG had no notes payable outstanding at December 31, 2024 and $83.3 million notes payable outstanding at December 31, 2023, 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 no debt outstanding under this agreement at December 31, 2024 and $20.9 million outstanding under this agreement at December 31, 2023, 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 no debt outstanding under this agreement at December 31, 2024 and $62.4 million outstanding under this agreement at December 31, 2023, 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. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates. 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, 2024 and December 31, 2023.

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 0.49 to 1.00 at December 31, 2024. We are not in default as of December 31, 2024.

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

At December 31, 2024 and 2023, 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 47 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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Lease cost** | | |
| Finance lease cost | | |
| Amortization of right-of-use assets | $ 3,265 | $ 3,503 |
| Interest on lease liabilities | 111 | 122 |
| Total finance lease cost | 3,376 | 3,625 |
| Operating lease cost | 1,225 | 1,429 |
| Short-term lease cost | 1,154 | 1,494 |
| Variable lease cost | 18 | 15 |
| Intercompany | (73) | (72) |
| **Total lease cost** | **$ 5,700** | **$ 6,491** |

Balance sheet and other information for the years ended December 31, 2024 and 2023 was as follows:

## Notes to Financial Statements

| As of December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands, except lease term and discount rate) | | | | |
| **Operating Leases** | | | | |
| Operating lease right of use assets | $ | 7,305 | $ | 8,202 |
| | | | | |
| Operating lease liabilities, current | | 1,318 | | 1,237 |
| Operating lease liabilities, long-term | | 7,167 | | 8,034 |
| Total operating lease liabilities | $ | 8,485 | $ | 9,271 |
| | | | | |
| **Finance Leases** | | | | |
| Other assets | $ | 24,971 | $ | 28,235 |
| | | | | |
| Other current liabilities | | 244 | | 230 |
| Other non-current liabilities | | 1,458 | | 1,479 |
| Total finance lease liabilities | $ | 1,702 | $ | 1,709 |
| | | | | |
| **Weighted-average Remaining Lease Term (years):** | | | | |
| Finance leases | | 6.08 | | 6.89 |
| Operating leases | | 8.66 | | 9.28 |
| **Weighted-average Discount Rate:** | | | | |
| Finance leases | | 5.33 % | | 5.65 % |
| Operating leases | | 3.56 % | | 3.51 % |

Supplemental cash flows information related to leases was as follows:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | | | |
| Operating cash flows from operating leases | $ | 1,368 | $ | 1,497 |
| Operating cash flows from finance leases | $ | 110 | $ | 108 |
| Financing cash flows from finance leases | $ | 224 | $ | 212 |
| | | | | |
| Right-of-use assets obtained in exchange for lease obligations: | | | | |
| Finance leases | $ | — | $ | — |
| Operating leases | $ | 381 | $ | 431 |

Maturities of lease liabilities were as follows:

| (Thousands) | Finance | Operating |
|---|---|---|
| **Years Ended December 31,** | | |
| 2025 | $ 324 | $ 1,472 |
| 2026 | 401 | 1,400 |
| 2027 | 401 | 1,013 |
| 2028 | 401 | 1,111 |
| 2029 | 401 | 783 |
| Thereafter | 97 | 4,174 |
| **Total lease payments** | **2,025** | **9,953** |
| Less: imputed interest | (323) | (1,468) |
| **Total** | **$ 1,702** | **$ 8,485** |

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 $96.2 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2024 and $92.2 million in 2023.

## Notes to Financial Statements

### 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 recorded a liability of $5.0 million as of December 31, 2024, 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 $5.6 million to $6.2 million as of December 31, 2024. 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 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 $48.6 million to $123.9 million at December 31, 2024. 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 $51.4 million at December 31, 2024 and $53.9 million at December 31, 2023. 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 2051.

**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 $7.4 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, 2024 and 2023, respectively, and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2024 and 2023, 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, 2024 | Electricity | Natural Gas | | 2024 | Electricity | Natural Gas |
| Regulatory assets | $ — | $ 115 | Electricity and natural gas purchased | | $ 29,300 | $ 3,730 |
| Regulatory liabilities | $ (12,359) | $ (136) | | | | |
| | | | | | | |
| December 31, 2023 | | | | 2023 | | |
| Regulatory assets | $ 16,807 | $ 3,211 | Electricity and natural gas purchased | | $ 75,022 | $ 5,618 |
| 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, 2024** | | |
| 2025 | 3,308,950 | 2,730,000 |
| 2026 | 473,575 | 360,000 |
| **As of December 31, 2023** | | |
| 2024 | 3,064,100 | 2,630,000 |
| 2025 | 717,600 | 370,000 |

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2024 and 2023, respectively, consisted of:

| December 31, 2024 | Derivative Assets-current | Derivative Assets-Non-current | Derivative Liabilities-current | Derivative Liabilities-Non-current |
|---|---|---|---|---|
| (Thousands) | | | | |
| Not designated as hedging instruments | | | | |
| Derivative assets | $ 24,554 | $ 3,498 | $ 13,933 | $ 1,624 |
| Derivative liabilities | (13,933) | (1,624) | (14,048) | (1,624) |
| | 10,621 | 1,874 | (115) | — |
| Designated as hedging instruments | | | | |
| Derivative assets | — | — | — | — |
| Derivative liabilities | — | — | — | — |
| | — | — | — | — |
| Total derivatives before offset of cash collateral | 10,621 | 1,874 | (115) | — |
| Cash collateral receivable | — | — | 115 | — |
| **Total derivatives as presented in the balance sheet** | **$ 10,621** | **$ 1,874** | **$ —** | **$ —** |

| 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** | **$ —** | **$ —** | **$ —** | **$ —** |

As of December 31, 2024 and 2023, 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, 2024 and 2023, 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) | | | | |
| **2024** | | | | |
| Interest rate contracts | $ — | Interest expense | $ — | $ 109,774 |
| **Total** | **$ —** | | **$ —** | |
| **2023** | | | | |
| Interest rate contracts | $ — | Interest expense | $ (44) | $ 86,858 |
| **Total** | **$ —** | | **$ (44)** | |

There is no gain (loss) amount in AOCI related to previously settled forward starting swaps and accumulated amortization as of December 31, 2024 and 2023. There was a net loss of $0.05 million in AOCI related to previously settled forward starting swaps and accumulated amortization, 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, 2024 is $0.1 million for which we have posted collateral.

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

The estimated fair value of debt amounted to $3,186 million and $2,720 million as of December 31, 2024 and 2023, 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, 2024 and 2023 consisted of:

| Description | (Level 1) | (Level 2) | (Level 3) | Netting | Total |
|---|---|---|---|---|---|
| **(Thousands)** | | | | | |
| **As of December 31, 2024** | | | | | |
| **Assets** | | | | | |
| Non-current investments available for sale, primarily money market funds | $ 9,316 | $ — | $ — | $ — | $ 9,316 |
| Derivatives | | | | | |
| Commodity contracts: | | | | | |
| Electricity | 27,481 | — | — | (15,122) | 12,359 |
| Natural gas | 571 | — | — | (435) | 136 |
| **Total** | **$ 37,368** | **$ —** | **$ —** | **$ (15,557)** | **$ 21,811** |
| **Liabilities** | | | | | |
| Derivatives | | | | | |
| Commodity contracts: | | | | | |
| Electricity | $ (15,123) | $ — | $ — | $ 15,123 | $ — |
| Natural gas | (549) | — | — | 549 | — |
| **Total** | **$ (15,672)** | **$ —** | **$ —** | **$ 15,672** | **$ —** |
| **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** | **$ —** |

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2024 and 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.

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.

### Note 14. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2024 and 2023, consisted of:

| (Thousands) | Balance, December 31, 2022 | Change 2023 | Balance, December 31, 2023 | Change 2024 | Balance, December 31, 2024 |
|---|---|---|---|---|---|
| Amortization of pension cost for non-qualified plans and current year actuarial gain (loss), net of income tax expense (benefit) of $9 for 2023 and ($27) for 2024 | $ (603) | $ 24 | $ (579) | $ (108) | $ (687) |
| Unrealized gain (loss) on derivatives qualified as hedges: | | | | | |
| Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax benefit of ($183) for 2023 and ($0) for 2024 | | 227 | | — | |
| Net unrealized gain (loss) on derivatives qualified as hedges | (217) | 227 | 10 | — | 10 |
| **Accumulated Other Comprehensive Loss** | **$ (820)** | **$ 251** | **$ (569)** | **$ (108)** | **$ (677)** |

### 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. During 2024, the Company decided to freeze pension benefit accruals for union employees.

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 $19.5 million for 2024 and $16.7 million for 2023.

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 $2.2 million and $2.4 million at December 31, 2024 and 2023, respectively.

### Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Change in benefit obligation** | | | | |
| Benefit obligation at January 1 | $ 1,159,963 | $ 1,136,121 | $ 94,493 | $ 95,760 |
| Service cost | 3,112 | 3,695 | 298 | 332 |
| Interest cost | 50,161 | 56,209 | 3,739 | 4,632 |
| Amendments | — | — | (14,593) | — |
| Actuarial (gain) loss | (55,754) | 57,264 | (1,600) | 6,238 |
| Curtailments | (13,169) | — | — | — |
| Benefits paid | (95,052) | (93,326) | (12,783) | (12,469) |
| **Benefit obligation at December 31** | **$ 1,049,261** | **$ 1,159,963** | **$ 69,554** | **$ 94,493** |
| **Change in plan assets** | | | | |
| Fair value of plan assets at January 1 | $ 1,114,333 | $ 1,115,006 | $ 20,238 | $ 29,337 |
| Actual return on plan assets | 14,528 | 92,653 | 2,931 | 4,658 |
| Employer & plan participants' contributions | — | — | 1,476 | — |
| Benefits paid | (95,052) | (93,326) | (12,783) | (13,757) |
| **Fair value of plan assets at December 31** | **$ 1,033,809** | **$ 1,114,333** | **$ 11,862** | **$ 20,238** |
| **Funded status** | **$ (15,452)** | **$ (45,630)** | **$ (57,692)** | **$ (74,255)** |

During 2024, the pension benefit obligation had an actuarial gain of $55.8 million. This gain was primarily driven by $63.9 million gain from increase in discount rates. During 2024, the pension benefit obligation had a reduction of $13.2 million from curtailments. The curtailments were driven by a Company decision to freeze pension benefit accruals for union employees. During 2024, the postretirement benefit obligation had an actuarial gain of $1.6 million. This gain was primarily driven by $3.2 million gain from increase in discount rates. During 2024, the postretirement benefit obligation had a reduction of $14.6 million from plan amendments.

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 obligations had an actuarial loss of $6.2 million. This loss was primarily driven by $3.3 million loss from decrease in discount rates.

Amounts recognized in the balance sheet as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Noncurrent liabilities | $ (15,452) | $ (45,630) | $ (57,692) | $ (74,255) |

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,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Net actuarial loss (gain) | $ 76,952 | $ 99,656 | $ (38,130) | $ (37,088) |
| Prior service credit | $ — | $ — | $ (13,118) | $ — |

Our accumulated benefit obligation for all qualified defined benefit pension plans was $1,049 million and $1,146 million as of December 31, 2024 and 2023, respectively. NYSEG's postretirement benefits were partially funded as of December 31, 2024 and 2023.

The projected benefit obligation exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2024 and 2023. The accumulated benefit obligation exceeded the fair value of pension plan assets as of December 31, 2024 and 2023. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2024 and 2023.

| **As of December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Projected benefit obligation | $ 1,049,261 | $ 1,159,963 |
| Accumulated benefit obligation | $ 1,049,261 | $ 1,145,637 |
| Fair value of plan assets | $ 1,033,809 | $ 1,114,333 |

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2024 and 2023.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **Years Ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Net periodic benefit cost** | | | | |
| Service cost | $ 3,112 | $ 3,695 | $ 298 | $ 332 |
| Interest cost | 50,161 | 56,209 | 3,739 | 4,632 |
| Expected return on plan assets | (84,615) | (75,845) | (950) | (1,165) |
| Amortization of prior service credit | — | — | (1,475) | — |
| Amortization of actuarial net loss (gain) | 23,868 | 1,626 | (2,540) | (6,537) |
| **Net periodic benefit cost** | **$ (7,474)** | **$ (14,315)** | **$ (928)** | **$ (2,738)** |
| ***Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities*** | | | | |
| Current year actuarial net loss (gain) | $ 14,333 | $ 40,455 | $ (3,582) | $ 2,745 |
| Amortization of actuarial net (loss) gain | (23,868) | (1,626) | 2,540 | 6,537 |
| Amortization of prior service credit | — | — | 1,475 | — |
| Effect of curtailments on gain | (13,169) | — | — | — |
| Current year prior service (credit) cost | $ — | $ — | $ (14,593) | $ — |
| **Total recognized in regulatory assets and regulatory liabilities** | **$ (22,704)** | **$ 38,829** | **$ (14,160)** | **$ 9,282** |
| **Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities** | **$ (30,178)** | **$ 24,514** | **$ (15,088)** | **$ 6,544** |

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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| Discount rate | 5.33 % | 4.65 % | 5.26 % | 4.65 % |
| Rate of compensation increase | N/A | 2.50% Union | N/A | N/A |
| Interest crediting rate | 3.50 % | 3.50 % | 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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **Years Ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| Discount rate | 4.65% / 4.38% | 5.17% | 4.65% / 4.35% | 5.10 % |
| Expected long-term return on plan assets | 7.25% | 6.00% | 4.60 % | 3.97 % |
| Rate of compensation increase | 2.50% Union | 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, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| Health care cost trend rate (pre 65/post 65) | 8.90% /10.60% | 8.10% / 8.60% |
| 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 | 2039 / 2039 | 2031 / 2032 |

***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 2025.

***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)** | | | |
| 2025 | $ 98,678 | $ 8,908 | $ — |
| 2026 | $ 96,313 | $ 7,842 | $ — |
| 2027 | $ 93,997 | $ 7,292 | $ — |
| 2028 | $ 92,121 | $ 6,801 | $ — |
| 2029 | $ 89,675 | $ 6,283 | $ — |
| 2030-2034 | $ 406,028 | $ 25,337 | $ — |

***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, 2024, by asset category, consisted of:

| | | Fair Value Measurements | | |
|---|---|---|---|---|
| **Asset Category** | **Total** | **(Level 1)** | **(Level 2)** | **(Level 3)** |
| **(Thousands)** | | | | |
| **As of December 31, 2024** | | | | |
| Cash and cash equivalents | $ 44,027 | $ 841 | $ 43,186 | $ — |
| U.S. government securities | 165,058 | 165,058 | — | — |
| Common stocks | 15,455 | 15,455 | — | — |
| Registered investment companies | 24,510 | 24,510 | — | — |
| Corporate bonds | 424,497 | — | 424,497 | — |
| Common collective trusts | 237,795 | — | 237,795 | — |
| Other, principally annuity, fixed income | 24,825 | — | 24,825 | — |
| | **$ 936,167** | **$ 205,864** | **$ 730,303** | **$ —** |
| Other investments measured at net asset value | 97,642 | | | |
| **Total** | **$ 1,033,809** | | | |

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 | $ | 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** | | | | | | |

### 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.
- 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, 2024 consisted of:

| | | Fair Value Measurements | | |
|---|---|---|---|---|
| **Asset Category** | **Total** | **(Level 1)** | **(Level 2)** | **(Level 3)** |
| **(Thousands)** | | | | |
| **As of December 31, 2024** | | | | |
| Cash and cash equivalents | $ 1,786 | $ — | $ 1,786 | $ — |
| Registered investment companies | 10,076 | 10,076 | — | — |
| **Total** | **$ 11,862** | **$ 10,076** | **$ 1,786** | **$ —** |

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** | **$ —** |

### 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 Iberdrola common stock as of both December 31, 2024 and 2023.

### Note 16. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2024 and 2023, consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Interest and dividend income | $ | 2,654 | $ | — |
| Carrying costs on regulatory assets | | 37,908 | | 22,756 |
| Allowance for funds used during construction | | 32,393 | | 24,305 |
| Miscellaneous | | 4,696 | | 2,577 |
| **Total other income** | **$** | **77,651** | **$** | **49,638** |
| Pension non-service components | $ | 9,155 | $ | 19,143 |
| Miscellaneous | | (1,872) | | (5,515) |
| **Total other (deductions) income, net** | **$** | **7,283** | **$** | **13,628** |

### 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 $155.8 million for 2024 and $145.7 million for 2023. Cost for services includes amounts capitalized in utility plant, which was approximately $26.7 million in 2024 and $21.1 million in 2023. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by NYSEG to AGR and its subsidiaries were approximately $24.6 million for 2024 and $19.6 million for 2023. 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 $54.2 million at December 31, 2024 and $120.6 million at December 31, 2023 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $2.4 million at December 31, 2024 and $4.9 million at December 31, 2023 is from various companies. The balance in notes receivable from affiliates of $41.3 million is due from CMP. There were no notes receivable from affiliates at December 31, 2023. 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, 2024 and 2023.

**Note 18. Subsequent Events**

The company has performed a review of subsequent events through March 21, 2025, which is the date these financial statements were available to be issued.

On February 11, 2025, NYSEG Storm Funding, LLC, a company wholly-owned and consolidated by NYSEG, issued storm cost recovery bonds of $711 million pursuant to the Storm Recovery Cost Financing Order issued by the NYPSC. The bonds have interest rates ranging from 4.71% to 5.16% and final maturity ranging from May 2031 to May 2037. NYSEG Storm Funding, LLC was created in November 2024 to facilitate the securitization process and did not have any activity until the issuance of the storm cost recovery bonds in February 2025.

# Rochester Gas and Electric Corporation
## Financial Statements
## As of and for the Years Ended December 31, 2024 and 2023

## Rochester Gas and Electric Corporation

### Index

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

# Independent Auditors' Report

Stockholder and 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, 2024 and 2023, and the related statements of income, comprehensive income, changes in stockholder's 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, 2024 and 2023, 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 21, 2025

## Rochester Gas and Electric Corporation
## Statements of Income

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Operating Revenues** | **$ 1,248,659** | **$ 1,221,747** |
| **Operating Expenses** | | |
| Electricity purchased | 197,718 | 173,544 |
| Natural gas purchased | 93,019 | 122,212 |
| Operations and maintenance | 426,392 | 400,318 |
| Depreciation and amortization | 141,945 | 130,846 |
| Taxes other than income taxes, net | 163,589 | 156,091 |
| **Total Operating Expenses** | **1,022,663** | **983,011** |
| **Operating Income** | **225,996** | **238,736** |
| Other income | 29,676 | 19,711 |
| Other deductions | (5,693) | (6,438) |
| Interest expense, net of capitalization | (67,056) | (54,207) |
| **Income Before Tax** | **182,923** | **197,802** |
| Income tax expense | 39,713 | 43,605 |
| **Net Income** | **$ 143,210** | **$ 154,197** |

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

## Rochester Gas and Electric Corporation
## Statements of Comprehensive Income

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Net Income** | **$ 143,210** | **$ 154,197** |
| **Other Comprehensive Income, Net of Tax** | | |
| Amortization of pension cost for non-qualified plans and current year actuarial gain, net of income tax | 204 | 318 |
| 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** | **2,920** | **3,034** |
| **Comprehensive Income** | **$ 146,130** | **$ 157,231** |

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

## Rochester Gas and Electric Corporation
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 962 | $ 197 |
| Accounts receivable and unbilled revenues, net | 216,081 | 210,138 |
| Accounts receivable from affiliates | 2,474 | 2,858 |
| Notes receivable from affiliates | 45,400 | — |
| Fuel and natural gas in storage | 9,053 | 10,453 |
| Materials and supplies | 25,519 | 26,745 |
| Derivative assets | 6,821 | — |
| Broker margin accounts | — | 6,985 |
| Income tax receivable | — | 825 |
| Prepaid property taxes | 47,016 | 43,637 |
| Regulatory assets | 96,343 | 105,460 |
| Other current assets | 18,265 | 13,853 |
| **Total Current Assets** | **467,934** | **421,151** |
| Utility plant, at original cost | 5,661,407 | 5,381,423 |
| Less accumulated depreciation | (1,463,927) | (1,384,955) |
| **Net Utility Plant in Service** | **4,197,480** | **3,996,468** |
| Construction work in progress | 466,242 | 409,669 |
| **Total Utility Plant** | **4,663,722** | **4,406,137** |
| Operating lease right of use assets | 17,268 | 1,372 |
| **Regulatory and Other Assets** | | |
| Regulatory assets | 557,197 | 488,461 |
| Other | 33,453 | 42,749 |
| **Total Regulatory and Other Assets** | **590,650** | **531,210** |
| **Total Assets** | **$ 5,739,574** | **$ 5,359,870** |

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

## Rochester Gas and Electric Corporation
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| **(Thousands)** | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Current portion of debt | $ 150,343 | $ — |
| Notes payable to affiliates | — | 17,100 |
| Accounts payable and accrued liabilities | 224,901 | 202,636 |
| Accounts payable to affiliates | 60,440 | 58,427 |
| Interest accrued | 9,871 | 9,192 |
| Taxes accrued | 9,265 | 2,199 |
| Operating lease liabilities | 1,899 | 1,878 |
| Environmental remediation costs | 1,933 | 17,767 |
| Regulatory liabilities | 40,363 | 79,101 |
| Other | 60,545 | 73,025 |
| **Total Current Liabilities** | **559,560** | **461,325** |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | 521,092 | 528,741 |
| **Other Non-current Liabilities** | | |
| Deferred income taxes | 579,715 | 524,937 |
| Nuclear plant obligations | 145,500 | 138,182 |
| Pension and other postretirement | 97,568 | 98,117 |
| Operating lease liabilities | 17,480 | 1,274 |
| Asset retirement obligations | 2,091 | 2,206 |
| Environmental remediation costs | 66,727 | 62,834 |
| Other | 38,407 | 28,758 |
| **Total Regulatory and Other Liabilities** | **1,468,580** | **1,385,049** |
| Non-current debt | 1,740,119 | 1,738,065 |
| **Total Liabilities** | **3,768,259** | **3,584,439** |
| **Commitments and Contingencies** | | |
| **Common Stock Equity** | | |
| Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2024 and 2023) | 194,429 | 194,429 |
| Additional paid-in capital | 1,405,306 | 1,305,552 |
| Retained earnings | 513,841 | 420,631 |
| Accumulated other comprehensive loss | (25,023) | (27,943) |
| Treasury stock, at cost (4,379,300 shares at December 31, 2024 and 2023) | (117,238) | (117,238) |
| **Total Common Stock Equity** | **1,971,315** | **1,775,431** |
| **Total Liabilities and Equity** | **$ 5,739,574** | **$ 5,359,870** |

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

## Rochester Gas and Electric Corporation
## Statements of Cash Flows

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Cash Flow From Operating Activities:** | | |
| **Net income** | **$ 143,210** | **$ 154,197** |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 141,945 | 130,846 |
| Regulatory assets/liabilities amortization | (41,260) | (43,156) |
| Regulatory assets/liabilities carrying cost | (6,191) | (1,170) |
| Amortization of debt issuance costs | 2,080 | 1,630 |
| Deferred taxes | 42,770 | 49,844 |
| Pension cost | 4,895 | (902) |
| Accretion expenses | 116 | 122 |
| Gain from disposal of property | (283) | (47) |
| Other non-cash items | (16,584) | (5,930) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable, from affiliates, and unbilled revenues | (5,559) | 21,796 |
| Inventories | 2,626 | 17,772 |
| Accounts payable, to affiliates, and accrued liabilities | 16,129 | (54,094) |
| Taxes accrued | 7,891 | (14,137) |
| Other assets/liabilities | 11,750 | (14,328) |
| Regulatory assets/liabilities | (76,207) | (157,145) |
| **Net Cash Provided by Operating Activities** | **227,328** | **85,298** |
| **Cash Flow From Investing Activities:** | | |
| Capital expenditures | (384,248) | (421,114) |
| Contributions in aid of construction | 15,663 | 11,470 |
| Proceeds from sale of property, plant and equipment | 4,256 | 26,498 |
| Notes receivable from affiliates | (45,400) | — |
| **Net Cash Used in Investing Activities** | **(409,729)** | **(383,146)** |
| **Cash Flow From Financing Activities:** | | |
| Non-current debt issuance | 152,242 | 246,084 |
| Repayments of finance leases | (1,976) | (3,843) |
| Notes payable to affiliates | (17,100) | (59,200) |
| Capital contributions | 100,000 | 225,000 |
| Dividends paid | (50,000) | (110,000) |
| **Net Cash Provided by Financing Activities** | **183,166** | **298,041** |
| **Net Increase in Cash and Cash Equivalents** | **765** | **193** |
| **Cash and Cash Equivalents, Beginning of Period** | **197** | **4** |
| **Cash and Cash Equivalents, End of Period** | **$ 962** | **$ 197** |

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, 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** |
| Net income | — | — | — | 143,210 | — | — | 143,210 |
| Other comprehensive income, net of tax | — | — | — | — | 2,920 | — | 2,920 |
| Comprehensive income | | | | | | | 146,130 |
| Stock-based compensation | — | — | (246) | — | — | — | (246) |
| Common stock dividends | — | — | — | (50,000) | — | — | (50,000) |
| Capital contributions | — | — | 100,000 | — | — | — | 100,000 |
| **Balance, December 31, 2024** | **38,885,813** | **$ 194,429** | **$ 1,405,306** | **$ 513,841** | **$ (25,023)** | **$ (117,238)** | **$ 1,971,315** |

(*) 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 392,400 electricity and 324,900 natural gas customers as of December 31, 2024, 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 a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Agreement and Plan of Merger:*** On May 17, 2024, AGR entered into an Agreement and Plan of Merger (the Merger Agreement) with Iberdrola and Arizona Merger Sub, Inc (Merger Sub). As a result of the consummation of the Merger on December 23, 2024 (closing date), Merger Sub merged with and into Avangrid (the Merger), with Avangrid continuing as the surviving corporation and a wholly-owned subsidiary of Iberdrola. On the closing date, each share of common stock issued and outstanding immediately prior to the closing date (other than common stock owned by the Merger, Merger Sub or any other direct or indirect wholly-owned Subsidiary of the Merger, and in each case not held on behalf of the third parties (collectively, the Excluded Shares)) was converted into a right to receive $35.75 per share of common stock in cash, without interest.

On the closing date, (i) all shares of common stock ceased to be outstanding, were cancelled and ceased to exist and (ii) each Excluded Share ceased to be outstanding and was cancelled without payment of any consideration and ceased to exist. As a result of the consummation of the Merger on December 23, 2024, Iberdrola became the direct owner of 100 shares of common stock of Avangrid which represents the only outstanding capital of the Company. On the closing date, the New York Stock Exchange (NYSE) filed with the Securities and Exchange Commission (the SEC) a notification of removal from listing on Form 25 in order to delist the common stock from the NYSE and deregister the common stock under Section 12(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Following the effectiveness of the Form 25, on January 2, 2025, Avangrid filed with the SEC a Form 15 requesting the termination of registration of the common stock under Section 12(g) of the Exchange Act and the suspension of reporting obligations under Section 13 and 15(d) of the Exchange Act with respect to the common stock.

***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 2024 and 2023. 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 $182.5 million as of December 31, 2024 and $178.0 million as of December 31, 2023. Depreciation expense was $133.4 million in 2024 and $123.1 million in 2023. Amortization of capitalized software was $8.5 million in 2024 and $7.7 million in 2023.

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) | 2024 | 2023 |
|---|---|---|---|
| (Thousands) | | | |
| Electric | 2-90 | $ 3,739,168 | $ 3,601,110 |
| Natural Gas | 7-80 | 1,284,600 | 1,229,480 |
| Common | 3-60 | 637,639 | 550,833 |
| **Utility plant at original cost** | | **5,661,407** | **5,381,423** |
| Less accumulated depreciation | | (1,463,927) | (1,384,955) |
| **Net Utility Plant in Service** | | **4,197,480** | **3,996,468** |
| Construction work in progress | | 466,242 | 409,669 |
| **Total Utility Plant** | | **$ 4,663,722** | **$ 4,406,137** |

***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:

| | | 2024 | | 2023 |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Cash paid (refunded) during the years ended December 31:** | | | | |
| Interest, net of amounts capitalized | $ | 67,572 | $ | 49,808 |
| Income taxes (refunded) paid, net | $ | (7,691) | $ | 8,421 |

Of the income taxes (refunded) paid, substantially all was (refunded by) paid to AGR under the tax sharing agreement. Interest capitalized was $11.2 million in 2024 and $14.3 million in 2023. Accrued liabilities for utility plant additions were $76.4 million as of December 31, 2024 and $65.4 million as of December 31, 2023.

***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 $63.5 million for 2024 and $64.8 million for 2023, and are shown net of an allowance for credit losses at December 31 of $59.5 million for 2024 and $44.5 million for 2023. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $48.8 million in 2024, including $0.6 million of arrears forgiveness balances. Credit loss expense was $41.1 million in 2023, including $17.6 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 $25.3 million in 2024 and $10.9 million in 2023. DPA receivable balances at December 31 were $41.6 million in 2024 and $23.9 million in 2023.

***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, 2024 and 2023 consisted of:

| (Thousands) | Government grants | Total |
|---|---|---|
| **As of December 31, 2022** | **$ 17,452** | **$ 17,452** |
| Disposals | — | — |
| Recognized in income | (400) | (400) |
| **As of December 31, 2023** | **17,052** | **17,052** |
| Disposals | — | — |
| Recognized in income | (400) | (400) |
| **As of December 31, 2024** | **$ 16,652** | **$ 16,652** |

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, 2024 and 2023.

***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, 2024 and 2023.

| **Years Ended December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| ARO, beginning of year | $ | 2,206 | $ | 2,312 |
| Liabilities settled during the year | | (231) | | (229) |
| Accretion expense | | 116 | | 123 |
| **ARO, end of year** | **$** | **2,091** | **$** | **2,206** |

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.

***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 payable balance due to AGR at December 31, 2024 is $6.5 million. The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2023 is $0.8 million.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established 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, 2024 and 2023.

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 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, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2024 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 standard is required to be adopted by private entities for the annual periods beginning after December 15, 2025. Early adoption is permitted. The two primary enhancements relate to disaggregation of the annual effective tax rate reconciliation and income taxes paid disclosures. 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) 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 43% 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.

**2023 RG&E Rate Case Filing**

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. An Order was issued on April 18, 2024 approving the Companies’ filed tariff amendments on a permanent basis. 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 RG&E's 2020 Rate Plan. Modifications to EAMs were approved by the Commission on October 12, 2023 in its Order approving RG&E's 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. On January 16, 2024, 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. On May 16, 2024, the NYPSC issued an Order approving a statewide Solar for All program, effective December 1, 2025, whereby utilities would aggregate bill credits generated by participating CDG projects and distribute them among customers automatically enrolled in the utility's low-income energy affordability programs that are located in a disadvantaged community. Also on May 16, 2024, the NYPSC issued an Order that permits CDG projects to offer up to three distinct CDG savings rates to CDG subscribers beginning June 1, 2025.

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 November 16, 2023, the Commission issued its Order Approving Midpoint Review Whitepaper's Recommendations with Modifications. The Order increased the total budget to $1.243 billion for the statewide program (NYSEG and RG&E combined share is approximately $131 million).

- 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. RG&E has tariffs in effect to collect costs for the procurement of qualified energy storage assets. On June 20, 2024, the NYPSC issued an Order establishing an updated storage goal and deployment policy.

- On April 18, 2024 the NYPSC instituted a proceeding intended to transition New York to a more connected, affordable, resilient, and clean electric grid. During the proceeding, Public Service Commission staff will engage with stakeholders to develop a comprehensive New York Grid of the Future plan that establishes targets for the deployment of flexible resources such as virtual power plants and identifies the utility investments needed to enable the grid of the future. The NYPSC is commencing this proceeding to establish a clear set of needed grid capabilities, establish targets for deployment of those capabilities, identify required investments to effectuate those targets, and identify the anticipated customer benefits and savings achievable from meeting those targets. NYPSC Staff filed a Grid Flexibility Study on January 31, 2025 and will develop and file the first iteration of the “New York Grid of the Future Plan” (Plan) by February 28, 2025.

- On August 15, 2024, the NYPSC issued an Order Establishing Proactive Planning Proceeding. The Order directs utilities to develop and propose a framework for a process to proactively plan for electric vehicles and electrification, and to identify urgent projects that may need to be deployed before the planning process is completed. On December 13, 2024, the Joint Utilities filed a long-term proactive planning framework.

**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.The CSRA requires utilities to obtain authorization from the Commission prior to seeking recovery of a 100% construction work in progress (CWIP) incentive associated with CLCPA Phase 2 projects. In an April 19, 2024 Order, the Commission granted the Company's request for authorization to seek a 100% CWIP incentive for its CLCPA Phase 2 projects. On July 5, 2024, FERC conditionally accepted RG&E's application for CWIP and the 100% Abandoned Plant incentive (Abandoned Plant), subject to further compliance, for projects that are subject to subsequent permitting approval by the NYPSC under Article VII of New York State's Public Service Law, effective July 8, 2024, and denied the application for CWIP and Abandoned Plant for projects not subject to Article VII permitting approval. RG&E is assessing the July 5, 2024 FERC order and the impacts on the companies. On August 2, 2024, RG&E sought clarification, or in the alternative rehearing, of the July 5, 2024 order. Rehearing was denied after 30 days by operation of law, and the order denying rehearing states that the issue will be addressed in a future order. On October 1, FERC ruled on RG&E's request for clarification/rehearing. FERC confirmed that any projects that receive state siting approval orders that include the required reliability and/or congestion reduction determinations can qualify for incentives, not limited to the projects listed in the July order as Article VII projects. FERC denied clarification and rehearing to include CWIP in rate base prior to FERC's acceptance of the state siting orders.

**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 $119.1 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of 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 $60.2 million for the year ended December 31, 2024.

Regulatory assets at December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Asset retirement obligation | $ | 3,204 | $ | 3,207 |
| Debt rate reconciliations | | 20,841 | | 8,128 |
| Decommissioning | | — | | 274 |
| Deferred meter replacement costs | | 11,232 | | 10,803 |
| Delivery rate shaping | | 21,291 | | 16,594 |
| Electric supply reconciliation | | 5,473 | | — |
| Environmental remediation costs | | 76,453 | | 66,671 |
| Federal tax depreciation normalization adjustment | | 40,748 | | 42,154 |
| Gas supply charges | | 5,007 | | — |
| Hedge losses | | 724 | | 13,991 |
| Low income program | | 2,139 | | 10,684 |
| Low income arrears forgiveness | | 22,488 | | 31,238 |
| Make-whole provision | | 15,559 | | 29,566 |
| Pension and other postretirement benefits | | 21,200 | | 22,288 |
| Pension and other postretirement benefits cost deferrals | | 13,926 | | 9,286 |
| Post term amortization | | 195 | | 781 |
| Rate adjustment mechanism | | 2,660 | | 7,769 |
| Revenue decoupling mechanism | | 26,072 | | 15,503 |
| Storm costs | | 64,844 | | 52,413 |
| Unamortized losses on reacquired debt | | 3,233 | | 3,676 |
| Uncollectible reserve | | 66,311 | | 41,986 |
| Unfunded future income taxes | | 160,777 | | 157,192 |
| Value of Distributed Energy Resources (VDER) Program | | 19,648 | | 16,730 |
| Other | | 49,515 | | 32,987 |
| **Total regulatory assets** | | **653,540** | | **593,921** |
| Less: current portion | | 96,343 | | 105,460 |
| **Total non-current regulatory assets** | **$** | **557,197** | **$** | **488,461** |

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 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.

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.

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

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period 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.

Gas supply charge 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.

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 RG&E 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, 2023, 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.

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 energy created by distributed energy resources, like solar.

Other includes items such as earnings sharing mechanism, methane detection program, danger tree, inside service line inspection and electric vehicle.

Regulatory liabilities at December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Accrued removal obligations | $ | 172,311 | $ | 173,561 |
| Asset retirement obligation | | 5,059 | | 4,955 |
| Carrying costs on deferred income tax bonus depreciation | | 514 | | 3,043 |
| Deferred property taxes | | 17,550 | | 15,276 |
| Deferred transmission congestion contracts | | 17,974 | | 26,489 |
| Earnings sharing | | 1,705 | | 4,563 |
| Economic development | | — | | 4,520 |
| Electric supply reconciliation | | — | | 4,247 |
| Energy efficiency programs | | 2,259 | | 4,196 |
| Gas supply charge | | — | | 1,092 |
| Mixed use 263(a) | | 388 | | 1,554 |
| NEIL (Nuclear Electric Insurance Limited) credits | | — | | 4,817 |
| Net plant reconciliation | | 7,876 | | 12,158 |
| Pension and other postretirement benefits | | 18,799 | | 17,723 |
| Pension and other postretirement benefits cost deferrals | | 2,112 | | 3,501 |
| Positive benefit adjustment | | 2,176 | | 8,704 |
| Service quality performance mechanism | | 19,015 | | 15,692 |
| Tax Act – remeasurement | | 246,736 | | 252,887 |
| Theoretical reserve flow through impact | | 419 | | 1,674 |
| Other | | 46,562 | | 47,190 |
| **Total regulatory liabilities** | | **561,455** | | **607,842** |
| Less: current portion | | 40,363 | | 79,101 |
| **Total non-current regulatory liabilities** | **$** | **521,092** | **$** | **528,741** |

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.

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.

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.

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.

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.

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), 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 $0.2 million at December 31, 2024, and $0.6 million at December 31, 2023, and are presented in "Other current liabilities" on our balance sheets. We recognized $0.7 million as revenue in 2024 and $1.0 million in 2023.

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, 2024 and 2023 are as follows:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Regulated operations – electricity | $ 867,619 | $ 835,405 |
| Regulated operations – natural gas | 325,224 | 345,250 |
| Other (a) | 21,457 | 14,945 |
| **Revenue from contracts with customers** | **1,214,300** | **1,195,600** |
| Leasing revenue | 82 | 68 |
| Alternative revenue programs | 26,822 | 20,670 |
| Other revenue | 7,455 | 5,409 |
| **Total operating revenues** | **$ 1,248,659** | **$ 1,221,747** |

(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, 2024 and 2023 consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Current | | | | |
| Federal | $ | (3,342) | $ | (5,892) |
| State | | 285 | | (347) |
| **Current taxes charged to benefit** | | **(3,057)** | | **(6,239)** |
| Deferred | | | | |
| Federal | | 32,200 | | 37,738 |
| State | | 10,570 | | 12,106 |
| **Deferred taxes charged to expense** | | **42,770** | | **49,844** |
| **Total Income Tax Expense** | **$** | **39,713** | **$** | **43,605** |

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, 2024 and 2023, respectively, consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Tax expense at federal statutory rate | $ | 38,414 | $ | 41,538 |
| Equity AFUDC tax impacts not normalized | | (2,830) | | (1,916) |
| Excess ADIT amortization | | (3,403) | | (5,557) |
| State tax expense, net of federal benefit | | 8,575 | | 9,290 |
| Other, net | | (1,043) | | 250 |
| **Total Income Tax Expense** | **$** | **39,713** | **$** | **43,605** |

Income tax expense for the year ended December 31, 2024 was $1.3 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 21.7%. 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 ADIT amortization and Equity AFUDC tax effects. This resulted in an effective tax rate of 22.0%.

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, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Non-current Deferred Income Tax Liabilities (Assets)** | | | | |
| Property related | $ | 646,164 | $ | 614,015 |
| Unfunded future income taxes | | 41,138 | | 39,394 |
| Storms | | 16,947 | | 13,701 |
| Regulatory liability due to "Tax Cuts and Jobs Act" | | (64,484) | | (66,104) |
| Pension and other postretirement benefits | | (23,527) | | (24,957) |
| Derivative assets | | (8,777) | | (9,740) |
| Environmental | | 2,037 | | (3,641) |
| Federal and state net operating loss | | (78,236) | | (67,630) |
| Other | | 48,453 | | 29,899 |
| **Total Non-current Deferred Income Tax Liabilities** | **$** | **579,715** | **$** | **524,937** |
| Deferred tax assets | $ | 175,024 | $ | 172,072 |
| Deferred tax liabilities | | 754,739 | | 697,009 |
| **Net Accumulated Deferred Income Tax Liabilities** | **$** | **579,715** | **$** | **524,937** |

RG&E has gross federal net operating losses of $242.0 million and gross New York state net operating losses of $528.4 million for the year ended December 31, 2024. 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.

In 2024 the IRS issued private letter rulings  (“PLRs”) 20242002, 20242003, and 20242004 to three affiliated utilities (unrelated to RG&E) which held that the normalization rules do not permit a utility’s Net Operating Loss Carryforward (“NOLC”) Deferred Tax Asset (“DTA”) related to certain depreciation differences to be reduced by intercompany tax allocation payments. RG&E performed an analysis of its federal NOLs and recorded an excess ADIT remeasurement adjustment of $1.2 million as a result in order to comply with the IRS rulings.

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, 2024 and 2023 consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Beginning Balance** | $ | 48,526 | $ | 48,813 |
| Reduction for tax positions related to prior years | | (287) | | (287) |
| **Ending Balance** | **$** | **48,239** | **$** | **48,526** |

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, 2024 and December 31, 2023.

### Note 6. Long-term Debt

Long-term debt as of December 31, 2024 and 2023 consisted of:

| As of December 31, | | 2024 | | 2023 | |
|---|---|---|---|---|---|
| (Thousands, except interest rates) | Maturity Dates | Balances | Interest Rates | Balances | Interest Rates |
| First mortgage bonds (a) | 2025-2053 | $ 1,815,500 | 1.85%-8.00% | $ 1,660,500 | 1.85%-8.00% |
| Unsecured pollution control notes - fixed | 2025 | 91,900 | 3.00% | 91,900 | 3.00% |
| Unamortized debt issuance cost and discount | | (16,938) | | (14,335) | |
| **Total Debt** | | **1,890,462** | | **1,738,065** | |
| Less: debt due within one year, included in current liabilities | | 150,343 | | — | |
| **Total Non-current Debt** | | **$ 1,740,119** | | **$ 1,738,065** | |

(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 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 5.62%, $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%.

On November 20, 2024, RG&E issued a total $155 million aggregate principal amount of green mortgage bonds, consisting of $77 million maturing in 2035 at an interest rate of 5.41%, $78 million maturing in 2038 at an interest rate of 5.51%.

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

| 2025 | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| $ 150,343 | $ — | $ 450,000 | $ 100,000 | $ — | $ 700,343 |

We have no financial debt covenant requirements related to our long-term debt at December 31, 2024 and 2023.

### Note 7. Bank Loans and Other Borrowings

RG&E had no outstanding balance as of December 31, 2024 and $17.1 million of notes payable outstanding as of December 31, 2023. 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 outstanding balance under this agreement as of December 31, 2024 and 2023.

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 no outstanding balance under this agreement as of December 31, 2024 and $17.1 million as of December 31, 2023.

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. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates. 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, 2024 and 2023.

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, 2024. We are not in default as of December 31, 2024.

**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 12 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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Lease cost** | | |
| Finance lease cost | | |
| Amortization of right-of-use assets | $ 2,484 | $ 4,208 |
| Interest on lease liabilities | 846 | 1,006 |
| Total finance lease cost | 3,330 | 5,214 |
| Operating lease cost | 2,002 | 516 |
| Short-term lease cost | 1,579 | 822 |
| Variable lease cost | 562 | 367 |
| Intercompany | 73 | 72 |
| **Total lease cost** | **$ 7,546** | **$ 6,991** |

Balance sheet and other information for the years ended December 31, 2024 and 2023 was as follows:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except lease term and discount rate) | | |
| **Operating Leases** | | |
| Operating lease right-of-use assets | $ 17,268 | $ 1,372 |
| | | |
| Operating lease liabilities, current | 1,899 | 1,878 |
| Operating lease liabilities, long-term | 17,480 | 1,274 |
| Total operating lease liabilities | $ 19,379 | $ 3,152 |
| | | |
| **Finance Leases** | | |
| Other assets | $ 30,378 | $ 40,868 |
| | | |
| Other current liabilities | 2,270 | 21,624 |
| Other non-current liabilities | 27,791 | 18,353 |
| Total finance lease liabilities | $ 30,061 | $ 39,977 |
| | | |
| **Weighted-average Remaining Lease Term (years):** | | |
| Finance leases | 10.85 | 6.69 |
| Operating leases | 6.88 | 4.64 |
| **Weighted-average Discount Rate:** | | |
| Finance leases | 3.38 % | 2.26 % |
| Operating leases | 4.76 % | 4.24 % |

Supplemental cash flows information related to leases was as follows:

| For the Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash flows from operating leases | $ 2,202 | $ 236 |
| Operating cash flows from finance leases | $ 911 | $ 970 |
| Financing cash flows from finance leases | $ 1,976 | $ 3,843 |
| | | |
| Right-of-use assets obtained in exchange for lease obligations: | | |
| Finance leases | $ (7,941) | $ — |
| Operating leases | $ 17,255 | $ 1,402 |

As of December 31, 2024, maturities of lease liabilities were as follows:

| | Finance Leases | Operating Leases |
|---|---|---|
| (Thousands) | | |
| **Years ending December 31,** | | |
| 2025 | $ 3,104 | $ 2,549 |
| 2026 | 3,129 | 2,636 |
| 2027 | 3,159 | 2,718 |
| 2028 | 3,189 | 2,683 |
| 2029 | 3,236 | 2,590 |
| Thereafter | 19,942 | 10,358 |
| **Total lease payments** | **35,759** | **23,534** |
| Less: imputed interest | (5,698) | (4,155) |
| **Total** | **$ 30,061** | **$ 19,379** |

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 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 $60.9 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2024 and $56.4 million in 2023.

**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, 2024, related to eight sites. We have recorded an estimated liability of $4.9 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 $4.5 million to $5.3 million as of December 31, 2024. 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 2025. 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 $59.2 million to $82.6 million at December 31, 2024. 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 $63.7 million at December 31, 2024, and $75.3 million at December 31, 2023. 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 2056.

**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 $4.7 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, 2024 and 2023 and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2024 and 2023 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, 2024** | **Electricity** | **Natural Gas** | **2024** | **Electricity** | **Natural Gas** |
| Regulatory assets | $ — | $ 724 | Electricity and natural gas purchased | $ 11,245 | $ 9,587 |
| Regulatory liabilities | $ (7,453) | $ (444) | | | |
| **December 31, 2023** | | | **2023** | | |
| Regulatory assets | $ 5,212 | $ 8,779 | Electricity and natural gas purchased | $ 26,911 | $ 9,139 |
| 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, 2024** | | |
| 2025 | 1,613,575 | 6,530,000 |
| 2026 | 186,550 | 1,030,000 |
| **As of December 31, 2023** | | |
| 2024 | 1,500,775 | 6,630,000 |
| 2025 | 321,000 | 1,030,000 |

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2024 and 2023, respectively, consisted of:

| December 31, 2024 | Derivative Assets Current | Derivative Assets Non-current | Derivative Liabilities Current | Derivative Liabilities Non-current |
|---|---|---|---|---|
| (Thousands) | | | | |
| Not designated as hedging instruments | | | | |
| Derivative assets | $ 12,824 | $ 1,852 | $ 6,003 | $ 775 |
| Derivative liabilities | (6,003) | (775) | (6,727) | (775) |
| | 6,821 | 1,077 | (724) | — |
| Designated as hedging instruments | | | | |
| Derivative assets | — | — | — | — |
| Derivative liabilities | — | — | — | — |
| | — | — | — | — |
| Total derivatives before offset of cash collateral | 6,821 | 1,077 | (724) | — |
| Cash collateral receivable | — | — | 724 | — |
| **Total derivatives as presented in the balance sheet** | **$ 6,821** | **$ 1,077** | **$ —** | **$ —** |

| 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** | **$ —** | **$ —** | **$ —** | **$ —** |

As of both December 31, 2024 and 2023, 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, 2024 and 2023, 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) | | | | |
| **2024** | | | | |
| Interest rate contracts | $ — | Interest expense | $ (3,678) | $ 67,056 |
| **Total** | **$ —** | | **$ (3,678)** | |
| **2023** | | | | |
| Interest rate contracts | $ — | Interest expense | $ (3,678) | $ 54,207 |
| **Total** | **$ —** | | **$ (3,678)** | |

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization at December 31, 2024 is a net loss of $33.6 million as compared to $37.3 million at December 31, 2023. For the year ended December 31, 2024, 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 2025.

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, 2024 is $0.7 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 $1,826 million as of December 31, 2024 and $1,703 million as of December 31, 2023. 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, 2024 and 2023 consisted of:

| Description | Level 1 | Level 2 | Level 3 | Netting | Total |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| **As of December 31, 2024** | | | | | |
| **Assets** | | | | | |
| Derivatives | | | | | |
| Commodity contracts: | | | | | |
| Electricity | $ 13,372 | $ — | $ — | $ (5,919) | $ 7,453 |
| Natural Gas | 1,304 | — | — | (859) | 445 |
| **Total** | **$ 14,676** | **$ —** | **$ —** | **$ (6,778)** | **$ 7,898** |
| **Liabilities** | | | | | |
| Derivatives | | | | | |
| Commodity contracts: | | | | | |
| Electricity | $ (5,919) | $ — | $ — | $ 5,919 | $ — |
| Natural gas | (1,583) | — | — | 1,583 | — |
| **Total** | **$ (7,502)** | **$ —** | **$ —** | **$ 7,502** | **$ —** |

| 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** | **$ —** |

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2024. 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 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.

## Note 13. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2024 and 2023, consisted of:

| | Balance December 31, 2022 | 2023 Change | Balance December 31, 2023 | 2024 Change | Balance December 31, 2024 |
|---|---|---|---|---|---|
| **(Thousands)** | | | | | |
| Amortization of pension cost for non-qualified plans and current year actuarial gain, net of tax expense of $113 for 2023 and $72 for 2024 | $ (738) | $ 318 | $ (420) | $ 204 | $ (216) |
| Unrealized gain (loss) on derivatives qualified as hedges: | | | | | |
| Reclassification adjustment for loss on settled cash flow treasury hedges included in net income, net of income tax expense of $962 for 2023 and $962 for 2024 | | 2,716 | | 2,716 | |
| Net unrealized gain on derivatives qualified as hedges | (30,239) | 2,716 | (27,523) | 2,716 | (24,807) |
| **Accumulated Other Comprehensive Loss** | **$ (30,977)** | **$ 3,034** | **$ (27,943)** | **$ 2,920** | **$ (25,023)** |

## 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 $10.3 million in 2024 and $9.1 million in 2023.

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 $7.4 million and $8.0 million at December 31, 2024 and 2023, respectively.

**Qualified Retirement Benefit Plans**

Obligations and funded status as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Change in benefit obligation** | | | | |
| Benefit obligation at January 1 | $ 243,974 | $ 252,879 | $ 43,362 | $ 44,661 |
| Service cost | — | — | 54 | 56 |
| Interest cost | 10,236 | 11,921 | 1,912 | 2,146 |
| Settlements | (14,149) | — | — | — |
| Actuarial (gain) loss | (4,131) | 11,548 | (3,091) | 25 |
| Benefits paid | (20,414) | (32,374) | (3,486) | (3,526) |
| **Benefit obligation at December 31** | **$ 215,516** | **$ 243,974** | **$ 38,751** | **$ 43,362** |
| **Change in plan assets** | | | | |
| Fair value of plan assets at January 1 | $ 184,499 | $ 201,556 | $ — | $ — |
| Actual return on plan assets | 2,298 | 15,317 | — | — |
| Employer and plan participants' contributions | — | — | 3,486 | 3,526 |
| Settlements | (14,149) | — | — | — |
| Benefits paid | (20,414) | (32,374) | (3,486) | (3,526) |
| **Fair value of plan assets at December 31** | **$ 152,234** | **$ 184,499** | **$ —** | **$ —** |
| **Funded status** | **$ (63,282)** | **$ (59,475)** | **$ (38,751)** | **$ (43,362)** |

During 2024, the pension benefit obligation had an actuarial gain of $4.1 million, primarily due to a $5.4 million gain from decrease in discount rates. In 2024, the pension benefit obligation had a reduction of $14.1 million from settlements. The settlements were lump sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. There were no significant gains or losses relating to the postretirement benefit obligations.

During 2023, the pension benefit obligation had an actuarial loss of $11.5 million, primarily due to a $5.4 million loss from increase in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2024 and 2023 consisted of:

| Amounts recognized in the balance sheet | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| December 31, | 2024 | 2023 | 2024 | 2023 |
| (Thousands) | | | | |
| Other current liabilities | $ — | $ — | $ (4,465) | $ (4,720) |
| Pension and other postretirement benefits | (63,282) | (59,475) | (34,286) | (38,642) |
| **Total** | **$ (63,282)** | **$ (59,475)** | **$ (38,751)** | **$ (43,362)** |

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, | 2024 | 2023 | 2024 | 2023 |
| (Thousands) | | | | |
| Net loss (gain) | $ 21,200 | $ 22,288 | $ (17,786) | $ (16,486) |
| Prior service credit | — | — | (1,013) | (1,237) |

Our accumulated benefit obligation for all qualified defined benefit pension plans was $215.5 million at December 31, 2024 and $244.0 million at December 31, 2023.

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, 2024 and 2023. 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, 2024 and 2023.

| December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Projected benefit obligation | $ 215,516 | $ 243,974 |
| Accumulated benefit obligation | $ 215,516 | $ 243,974 |
| Fair value of plan assets | $ 152,234 | $ 184,499 |

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2024 and 2023.

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, 2024 and 2023 consisted of:

| Years Ended December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Net periodic benefit cost** | | | | |
| Service cost | $ — | $ — | $ 54 | $ 56 |
| Interest cost | 10,236 | 11,921 | 1,912 | 2,146 |
| Expected return on plan assets | (13,006) | (13,265) | — | — |
| Amortization of prior service credit | — | — | (224) | (224) |
| Amortization of net loss (gain) | 6,319 | 441 | (1,791) | (2,087) |
| Settlement charge | 1,345 | — | — | — |
| **Net periodic benefit cost** | **$ 4,894** | **$ (903)** | **$ (49)** | **$ (109)** |
| **Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities** | | | | |
| Net loss (gain) | $ 6,576 | $ 9,495 | $ (3,091) | $ 24 |
| Amortization of net (gain) loss | (6,319) | (441) | 1,791 | 2,087 |
| Settlement charge | (1,345) | — | — | — |
| Amortization of prior service credit | — | — | 224 | 224 |
| **Total recognized in regulatory assets and regulatory liabilities** | **$ (1,088)** | **$ 9,054** | **$ (1,076)** | **$ 2,335** |
| **Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities** | **$ 3,806** | **$ 8,151** | **$ (1,125)** | **$ 2,226** |

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, 2024 and 2023 consisted of:

| | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| Discount rate | 5.12% | 4.70% | 5.19% | 4.66% |
| Rate of compensation increase | N/A | N/A | N/A | N/A |
| Interest crediting rate | 3.00% | 2.75% | 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, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **2024** | **2023** | **2024** | **2023** |
| Discount rate | 4.70% / 4.22% | 5.08% | 4.66% | 5.08% |
| Expected long-term return on plan assets | 7.25% | 6.00% | N/A | N/A |
| Rate of compensation increase | N/A | 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. 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, 2024 and 2023 consisted of:

| | **2024** | **2023** |
|---|---|---|
| Health care cost trend rate (pre 65/post 65) | 8.90% / 10.60% | 8.10% / 8.60% |
| 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 | 2039 / 2039 | 2031 / 2032 |

***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 2025. We expect to contribute $4.5 million to our postretirement benefit plans during 2025.

***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)** | | | |
| 2025 | $ 31,834 | $ 4,465 | $ — |
| 2026 | $ 27,590 | $ 4,329 | $ — |
| 2027 | $ 25,374 | $ 4,153 | $ — |
| 2028 | $ 23,127 | $ 3,959 | $ — |
| 2029 | $ 20,947 | $ 3,748 | $ — |
| 2030-2034 | $ 78,189 | $ 15,657 | $ — |

***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, 2024, consisted of:

| | | Fair Value Measurements at December 31, Using | | |
|---|---|---|---|---|
| **Asset Category** | **Total** | **Level 1** | **Level 2** | **Level 3** |
| **(Thousands)** | | | | |
| **2024** | | | | |
| Cash and cash equivalents | $ 6,101 | $ (32) | $ 6,133 | $ — |
| U.S. government securities | 19,868 | 19,868 | — | — |
| Common stocks | 7,015 | 7,015 | — | — |
| Registered investment companies | 13,300 | 13,300 | — | — |
| Corporate bonds | 18,894 | — | 18,894 | — |
| Common collective trusts | 53,438 | — | 53,438 | — |
| Other investments, principally annuity and fixed income | 2,310 | — | 2,310 | — |
| | **$ 120,926** | **$ 40,151** | **$ 80,775** | **$ —** |
| Other investments measured at net asset value | 31,308 | | | |
| **Total** | **$ 152,234** | | | |

The fair values of pension benefits plan assets, by asset category, as of December 31, 2023, consisted of:

| Asset Category | Total | Fair Value Measurements at December 31, Using 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** | | | |

*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 Iberdrola common stock as of both December 31, 2024 and 2023.

### Note 15. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2024 and 2023, consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Interest and dividend income | $ | 544 | $ | — |
| Allowance for funds used during construction | | 15,999 | | 11,321 |
| Carrying costs on regulatory assets | | 12,747 | | 7,812 |
| Miscellaneous | | 386 | | 578 |
| **Total other income** | **$** | **29,676** | **$** | **19,711** |
| Pension non-service components | $ | (4,839) | $ | 666 |
| Miscellaneous | | (854) | | (7,104) |
| **Total other deductions** | **$** | **(5,693)** | **$** | **(6,438)** |

### 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 $82.8 million in 2024 and $83.7 million in 2023. Cost for services includes amounts capitalized in utility plant, which was approximately $14.6 million in 2024 and $13.4 million in 2023. 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 $26.9 million in 2024 and $22.8 million in 2023. 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 $60.4 million at December 31, 2024 and $58.4 million at December 31, 2023 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $2.5 million at December 31, 2024 and $2.9 million at December 31, 2023 is from various companies.

Notes receivable from affiliates at December 31, 2024 and at December 31, 2023 were $45.4 million and $0, respectively. 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 21, 2025, which is the date these financial statements were available to be issued.

On February 14, 2025, RG&E Storm Funding, LLC, a company wholly-owned and consolidated by RG&E, issued storm cost recovery bonds of $75 million pursuant to the Storm Recovery Cost Financing Order issued by the NYPSC. The bonds have an interest rate of 4.93% and a final maturity of May 2037. RG&E Storm Funding, LLC was created in November 2024 to facilitate the securitization process and did not have any activity until the issuance of the storm cost recovery bonds in February 2025.

# The Southern Connecticut Gas Company
## Consolidated Financial Statements
## As of and for the Years Ended December 31, 2024 and 2023

# 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, 2024 and 2023, 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, 2024 and 2023, 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 28, 2025

## The Southern Connecticut Gas Company
## Consolidated Statements of Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Operating Revenues** | $ | **416,322** | $ | **426,092** |
| **Operating Expenses** | | | | |
| Natural gas purchased | | 165,854 | | 190,283 |
| Operations and maintenance | | 108,566 | | 101,292 |
| Depreciation and amortization | | 46,057 | | 42,412 |
| Taxes other than income taxes, net | | 36,551 | | 35,557 |
| **Total Operating Expenses** | | **357,028** | | **369,544** |
| **Operating Income** | | **59,294** | | **56,548** |
| Other income | | 6,173 | | 2,639 |
| Other deductions | | (5,157) | | (2,376) |
| Interest expense, net of capitalization | | (24,675) | | (18,227) |
| **Income Before Income Tax** | | **35,635** | | **38,584** |
| Income tax expense | | 6,170 | | 6,904 |
| **Net Income** | | **29,465** | | **31,680** |
| Less: net income attributable to noncontrolling interest | | 3,754 | | 2,673 |
| **Net Income Attributable to SCG** | $ | **25,711** | $ | **29,007** |

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, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Net Income** | $ | **29,465** | $ | **31,680** |
| **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 expense of $8 for 2024 and income tax benefit of ($57) for 2023 | | 21 | | (154) |
| **Total Other Comprehensive Income (Loss), Net of Tax** | | **21** | | **(154)** |
| **Comprehensive Income** | | **29,486** | | **31,526** |
| Less: Comprehensive income attributable to noncontrolling interest | | 3,754 | | 2,673 |
| **Comprehensive Income Attributable to SCG** | $ | **25,732** | $ | **28,853** |

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

## The Southern Connecticut Gas Company
## Consolidated Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 2,684 | $ 380 |
| Accounts receivable and unbilled revenues, net | 109,267 | 103,015 |
| Accounts receivable from affiliates | 1,186 | 648 |
| Notes receivable from affiliates | 41,420 | 15,259 |
| Gas in storage | 37,662 | 45,886 |
| Materials and supplies | 4,831 | 4,400 |
| Other current assets | 4,465 | 4,047 |
| Regulatory assets | 64,898 | 48,064 |
| **Total Current Assets** | **266,413** | **221,699** |
| Utility plant, at original cost | 1,544,496 | 1,435,400 |
| Less accumulated depreciation | (433,337) | (403,611) |
| **Net Utility Plant in Service** | **1,111,159** | **1,031,789** |
| Construction work in progress | 28,015 | 26,905 |
| **Total Utility Plant** | **1,139,174** | **1,058,694** |
| Operating lease right-of-use assets | 10,440 | 11,256 |
| Other property and investments | 11,360 | 10,396 |
| **Regulatory and Other Assets** | | |
| Regulatory assets | 160,132 | 163,696 |
| Goodwill | 134,931 | 134,931 |
| Other | 471 | 372 |
| **Total Regulatory and Other Assets** | **295,534** | **298,999** |
| **Total Assets** | **$ 1,722,921** | **$ 1,601,044** |

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

## The Southern Connecticut Gas Company
## Consolidated Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except share information) | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Current portion of long-term debt | $ 25,196 | $ — |
| Notes payable to affiliates | 67,600 | 2,087 |
| Accounts payable and accrued liabilities | 74,512 | 71,892 |
| Accounts payable to affiliates | 23,114 | 20,927 |
| Interest accrued | 4,569 | 4,096 |
| Taxes accrued | 7,472 | 12,324 |
| Operating lease liabilities | 990 | 904 |
| Regulatory liabilities | 37,636 | 6,279 |
| Other | 22,589 | 21,794 |
| **Total Current Liabilities** | **263,678** | **140,303** |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | 213,213 | 245,911 |
| **Other Non-current Liabilities** | | |
| Deferred income taxes | 123,888 | 109,708 |
| Pension and other postretirement | 36,417 | 48,122 |
| Operating lease liabilities | 10,664 | 11,364 |
| Asset retirement obligation | 13,020 | 12,907 |
| Environmental remediation costs | 59,737 | 60,624 |
| Other | 6,943 | 7,071 |
| **Total Regulatory and Other Liabilities** | **463,882** | **495,707** |
| Non-current debt | 369,184 | 364,471 |
| **Total Liabilities** | **1,096,744** | **1,000,481** |
| **Commitments and Contingencies** | | |
| **Common Stock Equity** | | |
| Common stock ($13.33 par value, 2,650,000 shares authorized and 1,407,072 shares outstanding at December 31, 2024 and 2023) | 18,761 | 18,761 |
| Additional paid-in capital | 472,737 | 472,737 |
| Retained earnings | 97,033 | 71,322 |
| Accumulated other comprehensive loss | (5,349) | (5,370) |
| **Total SCG Common Stock Equity** | **583,182** | **557,450** |
| Noncontrolling interest | 42,995 | 43,113 |
| **Total Equity** | **626,177** | **600,563** |
| **Total Liabilities and Equity** | **$ 1,722,921** | **$ 1,601,044** |

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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Cash Flow from Operating Activities:** | | |
| **Net income** | **$ 29,465** | **$ 31,680** |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 46,057 | 42,412 |
| Regulatory assets/liabilities amortization | 16,024 | 13,360 |
| Regulatory assets/liabilities carrying cost | 4,487 | 3,996 |
| Amortization of debt issuance costs | (157) | (195) |
| Deferred taxes | 11,109 | 1,928 |
| Pension cost | 1,185 | 2,274 |
| Accretion expenses | 662 | 656 |
| Gain on disposal of assets | (48) | (39) |
| Other non-cash items | (72) | (74) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable, from affiliates, and unbilled revenues | (6,790) | 31,379 |
| Inventories | 7,793 | 11,505 |
| Accounts payable, to affiliates, and accrued liabilities | 12,417 | (35,035) |
| Taxes accrued | (4,851) | 831 |
| Other assets/liabilities | 9,825 | 5,496 |
| Regulatory assets/liabilities | (60,509) | (26,775) |
| **Net Cash Provided by Operating Activities** | **66,597** | **83,399** |
| **Cash Flow from Investing Activities:** | | |
| Capital expenditures | (133,087) | (100,910) |
| Contributions in aid of construction | 3,356 | 2,914 |
| Proceeds from sale of utility plant | 119 | 181 |
| Notes receivable from affiliates | (26,161) | (13,599) |
| **Net Cash Used in Investing Activities** | **(155,773)** | **(111,414)** |
| **Cash Flow from Financing Activities:** | | |
| Non-current debt issuance | 29,839 | 59,649 |
| Notes payable to affiliates | 65,513 | (22,513) |
| Capital contributions | — | 10,000 |
| Contributions from noncontrolling interest | 2,087 | — |
| Dividends paid | — | (20,000) |
| Payment of noncontrolling interest dividend | (5,959) | — |
| **Net Cash Provided by Financing Activities** | **91,480** | **27,136** |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | **2,304** | **(879)** |
| **Cash and Cash Equivalents, Beginning of Period** | **380** | **1,259** |
| **Cash and Cash Equivalents, End of Period** | **$ 2,684** | **$ 380** |

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, 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** |
| Net income | — | — | — | 25,711 | — | — | 25,711 |
| Other comprehensive income, net of tax | — | — | — | — | 21 | — | 21 |
| Comprehensive income | | | | | | | 25,732 |
| Net income attributable to noncontrolling interest | — | — | — | — | — | 3,754 | 3,754 |
| Payment of noncontrolling interest dividend | — | — | — | — | — | (5,959) | (5,959) |
| Contributions from noncontrolling interest | — | — | — | — | — | 2,087 | 2,087 |
| **Balance, December 31, 2024** | **1,407,072** | **$ 18,761** | **$ 472,737** | **$ 97,033** | **$ (5,349)** | **$ 42,995** | **$ 626,177** |

(*) 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 210,000 customers as of December 31, 2024, 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 a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Agreement and Plan of Merger:*** On May 17, 2024, AGR entered into an Agreement and Plan of Merger (the Merger Agreement) with Iberdrola and Arizona Merger Sub, Inc (Merger Sub). As a result of the consummation of the Merger on December 23, 2024 (closing date), Merger Sub merged with and into Avangrid (the Merger), with Avangrid continuing as the surviving corporation and a wholly-owned subsidiary of Iberdrola. On the closing date, each share of common stock issued and outstanding immediately prior to the closing date (other than common stock owned by the Merger, Merger Sub or any other direct or indirect wholly-owned Subsidiary of the Merger, and in each case not held on behalf of the third parties (collectively, the Excluded Shares)) was converted into a right to receive $35.75 per share of common stock in cash, without interest.

On the closing date, (i) all shares of common stock ceased to be outstanding, were cancelled and ceased to exist and (ii) each Excluded Share ceased to be outstanding and was cancelled without payment of any consideration and ceased to exist. As a result of the consummation of the Merger on December 23, 2024, Iberdrola became the direct owner of 100 shares of common stock of Avangrid which represents the only outstanding capital of the Company. On the closing date, the New York Stock Exchange (NYSE) filed with the Securities and Exchange Commission (the SEC) a notification of removal from listing on Form 25 in order to delist the common stock from the NYSE and deregister the common stock under Section 12(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Following the effectiveness of the Form 25, on January 2, 2025, Avangrid filed with the SEC a Form 15 requesting the termination of registration of the common stock under Section 12(g) of the Exchange Act and the suspension of reporting obligations under Section 13 and 15(d) of the Exchange Act with respect to the common stock.

***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 $54.1 million and income of $3.8 million as of and for the year ended December 31, 2024. 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. On December 1, 2024, the sole member of CNE and TPS, authorized the sale of the LNG facility and gas inventory to SCG.

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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Assets** | | |
| Current assets | $ 54,059 | $ 18,914 |
| Long-term assets | — | 29,386 |
| **Total Assets** | **54,059** | **48,300** |
| | | |
| **Liabilities** | | |
| Current liabilities | 11,064 | 4,834 |
| Long-term liabilities | — | 353 |
| **Total Liabilities** | **$ 11,064** | **$ 5,187** |

***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.

## Notes to Consolidated Financial Statements

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 2024 and 2023. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 10 years. Depreciation expense was $42.1 million in 2024 and $38.4 million in 2023. Amortization of capitalized software was $4.0 million in both 2024 and 2023.

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) | 2024 | 2023 |
|---|---|---|---|
| **(Thousands)** | | | |
| Gas distribution plant | 6-78 | $ 1,381,997 | $ 1,275,329 |
| Software | 3-10 | 61,535 | 59,497 |
| Land | N/A | 7,663 | 7,663 |
| Building and improvements | 40-50 | 43,314 | 40,424 |
| VIE | 10-50 | — | 47,104 |
| Other plant | 25-39 | 49,987 | 5,383 |
| **Total Utility Plant in Service** | | **1,544,496** | **1,435,400** |
| Total accumulated depreciation | | (433,337) | (403,611) |
| **Total Net Utility Plant in Service** | | **1,111,159** | **1,031,789** |
| Construction work in progress | | 28,015 | 26,905 |
| **Total Utility Plant** | | **$ 1,139,174** | **$ 1,058,694** |

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

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

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

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

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

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

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

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

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

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

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

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

***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:

| | | 2024 | | 2023 |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Cash paid (refunded) during the years ended December 31:** | | | | |
| Interest, net of amounts capitalized | $ | 17,394 | $ | 12,904 |
| Income taxes paid (refunded), net | $ | (371) | $ | 3,511 |

Of the income taxes paid (refunded), substantially all was paid to (refunded by) AGR under the tax sharing agreement. Interest capitalized was $0.9 million in both 2024 and 2023. Accrued liabilities for utility plant additions were $18.4 million and $25.0 million as of December 31, 2024 and 2023, 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 million for 2024 and $24.5 million for 2023, and are shown net of an allowance for credit losses at December 31 of $6.8 million for 2024 and $6.8 million for 2023. Trade receivable do not bear interest, although late fees may be assessed. Credit loss expense was $3.8 million in 2024 and $5.3 million in 2023.

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, 2024 and 2023.

***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, 2024 and 2023.

| **Years ended December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| ARO, beginning of year | $ | 12,907 | $ | 12,785 |
| Liabilities settled during the year | | (549) | | (533) |
| Accretion expense | | 662 | | 655 |
| **ARO, end of year** | **$** | **13,020** | **$** | **12,907** |

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.

***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 $3.3 million and $7.7 million at December 31, 2024 and 2023, 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, 2024 and 2023.

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, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2024 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 standard is required to be adopted by private entities for the annual periods beginning after December 15, 2025. Early adoption is permitted. The two primary enhancements relate to disaggregation of the annual effective tax rate reconciliation and income taxes paid disclosures. 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 72% of our employees are covered by collective bargaining agreements. We have no collective bargaining agreements expiring during 2025.

## 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 approved 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 year ended December 31, 2023.

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. On November 19, 2024, PURA released a final Decision, where in it decreased SCG's rates by $10.7 million. The Decision approved an allowed ROE of 9.15% and an equity ratio of 53%.  The Decision maintained SCG's distribution management program, but instituted a cap of $57.7 million. The Decision also established a a low-income discount rate along with revenue decoupling and earning sharing mechanisms.  On December 19, 2024, SCG filed an appeal of the Decision in the Connecticut Superior Court. 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.

On December 1, 2024, SCG purchased 100% of the net book value of the LNG plant attached to its distribution system in Milford, CT. Prior to this date, SCG had the rights to 100% of the Liquefied Natural Gas stored in the LNG facility through agreements with Total Peaking Services and CNE Peaking. The transfer, approved by the Public Utilities Regulatory Authority in Docket No. 23-11-02, transferred ownership of the LNG facility from Total Peaking Services to SCG. 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 $130.6 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.

Regulatory assets at December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Asset retirement obligation | $ | 4,224 | $ | 4,064 |
| Debt premium | | 2,332 | | 2,921 |
| Deferred purchased gas | | 7,924 | | 280 |
| Distribution integrity management program | | 28,068 | | 19,312 |
| Environmental remediation costs | | 69,710 | | 69,111 |
| Pension and other postretirement benefits | | 53,016 | | 59,934 |
| Revenue decoupling mechanism | | 14,954 | | 14,532 |
| System expansion | | 11,197 | | 12,960 |
| Unfunded future income taxes | | 25,728 | | 22,703 |
| Other | | 7,877 | | 5,943 |
| **Total regulatory assets** | | **225,030** | | **211,760** |
| Less: current portion | | 64,898 | | 48,064 |
| **Total non-current regulatory assets** | **$** | **160,132** | **$** | **163,696** |

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. 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, 2024 and 2023 consisted of:

| **December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Asset removal obligation | $ 123,753 | $ 122,722 |
| Low income program | — | 4,561 |
| Non-firm margin sharing credits | 16,930 | 17,363 |
| Pension and other postretirement benefits | 5,438 | 5,349 |
| Rate credits | 2,250 | 3,000 |
| Tax reform | 89,030 | 79,816 |
| Unfunded future income taxes | 8,312 | 10,907 |
| Other | 5,136 | 8,472 |
| **Total regulatory liabilities** | **250,849** | **252,190** |
| Less: current portion | 37,636 | 6,279 |
| **Total non-current regulatory liabilities** | **$ 213,213** | **$ 245,911** |

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

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects. This balance is amortized through current rates.

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. 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 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, 2024 and 2023 are as follows:

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Regulated operations – natural gas | $ 400,156 | $ 406,164 |
| Other(a) | 2,031 | 873 |
| **Revenue from contracts with customers** | **402,187** | **407,037** |
| Leasing revenue | — | 2 |
| Alternative revenue programs | 12,018 | 15,217 |
| Other revenue | 2,117 | 3,836 |
| **Total operating revenues** | **$ 416,322** | **$ 426,092** |

(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 2024 and 2023 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2024 or 2023 that required us to update the assessment.

The carrying amount of goodwill was $134.9 million at both December 31, 2024 and 2023, with no accumulated impairment losses and no changes during 2024 and 2023.

### Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2024 and 2023 consisted of:

## Notes to Consolidated Financial Statements

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Current | | | | |
| Federal | $ | (3,861) | $ | (1,920) |
| State | | (1,078) | | 6,896 |
| **Current taxes charged to expense (benefit)** | | **(4,939)** | | **4,976** |
| Deferred | | | | |
| Federal | | 10,664 | | 9,593 |
| State | | 445 | | (7,665) |
| **Deferred taxes charged to expense** | | **11,109** | | **1,928** |
| **Total Income Tax Expense** | **$** | **6,170** | **$** | **6,904** |

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, 2024 and 2023, respectively, consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Tax expense at statutory rate | $ | 7,483 | $ | 8,103 |
| State tax expense, net of federal income tax benefit | | (500) | | (607) |
| Variable interest entity | | (1,033) | | (736) |
| Other, net | | 220 | | 144 |
| **Total Income Tax Expense** | **$** | **6,170** | **$** | **6,904** |

Income tax expense for the year ended December 31, 2024 was $1.3 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 17.3%. 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%.

Deferred tax assets and liabilities as of December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Non-current Deferred Income Tax Liabilities (Assets)** | | | | |
| Property related | $ | 152,513 | $ | 133,945 |
| Unfunded future income taxes | | 4,610 | | 3,101 |
| Valuation allowance - state credits | | 15,440 | | 13,675 |
| Federal and state tax credits | | (15,651) | | (13,883) |
| Goodwill | | 25,361 | | 23,571 |
| 2017 Tax Act remeasurement | | (23,971) | | (21,491) |
| Federal and state NOL's | | (51,121) | | (36,415) |
| Post-retirement benefits, net | | 3,178 | | 1,645 |
| Other | | 13,529 | | 5,560 |
| **Total Non-current Deferred Income Tax Liabilities** | **$** | **123,888** | **$** | **109,708** |
| Deferred tax assets | $ | 90,743 | $ | 71,789 |
| Deferred tax liabilities | | 214,631 | | 181,497 |
| **Net Accumulated Deferred Income Tax Liabilities** | **$** | **123,888** | **$** | **109,708** |

SCG has federal net operating losses of $36.0 million, net state net operating losses of $15.0 million and net state credit carryforward of $15.7 million for the year ended December 31, 2024. SCG had 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.

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, 2024, SCG had recorded a valuation allowance on its state tax credit carryforwards of $15.4 million. The company has also recorded a regulatory asset of $24.5 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, 2023, SCG had recorded a valuation allowance on its state 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

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, 2024 and 2023, 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, 2024 and 2023.

### Note 7. Long-term Debt

Long-term debt as of December 31, 2024 and 2023 consisted of:

| As of December 31, | | 2024 | | 2023 | |
|---|---|---|---|---|---|
| (Thousands, except interest rates) | Maturity Dates | Balances | Interest Rates | Balances | Interest Rates |
| First mortgage bonds (a) | 2025-2049 | $ 394,000 | 1.87% - 7.95% | $ 364,000 | 1.87% - 7.95% |
| Unamortized debt issuance premium, net | | 380 | | 471 | |
| **Total Debt** | | **394,380** | | **364,471** | |
| Less: debt due within one year, included in current liabilities | | 25,196 | | — | |
| **Total Non-current Debt** | | **$ 369,184** | | **$ 364,471** | |

(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% .

On August 15, 2024, SCG issued $30 million of first mortgage private bonds maturing in 2039 at an interest rate of 5.62%.

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

| 2025 | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| $ 25,196 | $ 15,000 | $ — | $ 14,000 | $ — | $ 54,196 |

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, 2024 and 2023, SCG was in compliance with long-term debt covenants.

**Note 8. Bank Loans and Other Borrowings**

Notes payable balances totaled $67.6 million and $2.1 million as of December 31, 2024 and 2023, 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 $53.7 million outstanding under this agreement at December 31, 2024 and no debt outstanding under this agreement at December 31, 2023.

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 $13.9 million outstanding under this agreement at December 31, 2024 and no debt outstanding under this agreement at December 31, 2023.

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. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates. 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, 2024 and 2023.

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 0.42 to 1.00 at December 31, 2024. We are not in default as of December 31, 2024.

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 SOFR plus an applicable margin and is capitalized annually. As of December 31, 2024 and 2023 TPS had no balance outstanding and $2.1 million, respectively, outstanding under its agreement. CNE did not have any amounts outstanding under this agreement as of December 31, 2024 and 2023.

## Note 9. Preferred Stock

At December 31, 2024, SCG had 200,000 shares of $100 par value preferred stock and 1,600,000 shares of $2 par value preferred stock authorized but unissued.

## Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. As of December 31, 2024 and 2023, 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 49 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, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Lease cost** | | |
| Operating lease cost | $ 1,195 | $ 1,160 |
| Short-term lease cost | 38 | 224 |
| Variable lease cost | 795 | 529 |
| **Total lease cost** | **$ 2,028** | **$ 1,913** |

Consolidated balance sheet and other information for the years ended December 31, 2024 and 2023 was as follows:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands, except lease term and discount rate) | | |
| **Operating Leases** | | |
| Operating lease right of use assets | $ 10,440 | $ 11,256 |
| | | |
| Operating lease liabilities, current | 990 | 904 |
| Operating lease liabilities, long-term | 10,664 | 11,364 |
| Total operating lease liabilities | $ 11,654 | $ 12,268 |
| | | |
| **Weighted-average Remaining Lease Term (years):** | | |
| Operating leases | 8.46 | 9.31 |
| **Weighted-average Discount Rate:** | | |
| Operating leases | 4.45 % | 4.18 % |

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

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash flows from operating leases | $ 1,377 | $ 1,168 |
| | | |
| Right-of-use assets obtained in exchange for lease obligations: | | |
| Operating leases | $ 352 | $ 1,735 |

Maturities of lease liabilities were as follows:

| | | Operating |
|---|---|---|
| (Thousands) | | |
| **Years Ended December 31,** | | |
| 2025 | $ | 1,402 |
| 2026 | | 1,443 |
| 2027 | | 2,067 |
| 2028 | | 1,441 |
| 2029 | | 1,484 |
| Thereafter | | 6,187 |
| **Total lease payments** | | **14,024** |
| Less: imputed interest | | (2,370) |
| **Total** | **$** | **11,654** |

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, 2024 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, 2024 and 2023, SCG reserved $51.8 million and $51.3 million, respectively, related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2024 and 2023, SCG reserved $11.5 million and $12.0 million, respectively, related to the property located on Pine Street in Bridgeport. As of December 31, 2024 and 2023, SCG has determined that remediation of the property on Housatonic Avenue in Bridgeport is not estimable at this time and therefore not reserved.

Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2050.

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

The estimated fair value of debt amounted to $376 million and $357 million as of December 31, 2024 and 2023, 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, 2024 and 2023 consisted of:

| Description | (Level 1) | (Level 2) | (Level 3) | Total |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **As of December 31, 2024** | | | | |
| **Assets** | | | | |
| Non-current investments | $ 11,360 | $ — | $ — | $ 11,360 |
| **Total** | **$ 11,360** | **$ —** | **$ —** | **$ 11,360** |
| | | | | |
| **As of December 31, 2023** | | | | |
| **Assets** | | | | |
| Non-current investments | $ 10,396 | $ — | $ — | $ 10,396 |
| **Total** | **$ 10,396** | **$ —** | **$ —** | **$ 10,396** |

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2024 and 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 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.

## Notes to Consolidated Financial Statements

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 $3.6 million for 2024 and $3.1 million for 2023.

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 $4.4 million and $4.7 million at December 31, 2024 and 2023, respectively.

### Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Change in benefit obligation** | | | | |
| Benefit obligation at January 1 | $ 127,093 | $ 124,074 | $ 16,721 | $ 15,164 |
| Service cost | — | — | 27 | 29 |
| Interest cost | 5,619 | 6,108 | 742 | 737 |
| Actuarial (gain) loss | (7,720) | 6,834 | (1,321) | 3,084 |
| Benefits paid | (10,732) | (9,923) | (1,854) | (2,293) |
| **Benefit obligation at December 31** | **$ 114,260** | **$ 127,093** | **$ 14,315** | **$ 16,721** |
| **Change in plan assets** | | | | |
| Fair value of plan assets at January 1 | $ 92,320 | $ 87,533 | $ 3,372 | $ 2,939 |
| Actual return on plan assets | 2,952 | 11,010 | 163 | 433 |
| Employer & plan participants' contributions | 4,858 | 3,700 | 1,079 | 2,293 |
| Benefits paid | (10,732) | (9,923) | (1,854) | (2,293) |
| **Fair value of plan assets at December 31** | **$ 89,398** | **$ 92,320** | **$ 2,760** | **$ 3,372** |
| **Funded status** | **$ (24,862)** | **$ (34,773)** | **$ (11,555)** | **$ (13,349)** |

During 2024, the pension benefit obligation had an actuarial gain of $7.7 million. This gain was primarily driven by a $6.9 million gain from increase in discount rates. During 2024, the postretirement benefit obligation had an actuarial gain of $1.3 million. This gain was primarily driven by $0.8 million gain from increase in discount rates.

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.

Amounts recognized in the consolidated balance sheet as of December 31, 2024 and 2023 consisted of:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| **As of December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Noncurrent liabilities | $ (24,862) | $ (34,773) | $ (11,555) | $ (13,349) |

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,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| Net actuarial loss | $ 15,190 | $ 21,328 | $ 52 | $ 1,524 |
| Prior service cost | $ 1,610 | $ 1,712 | $ — | $ 396 |

Our accumulated benefit obligation for all qualified defined benefit pension plans was $114.3 million and $127.1 million as of December 31, 2024 and 2023, respectively. SCG's postretirement benefits were partially funded as of December 31, 2024 and 2023.

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, 2024 and 2023. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2024 and 2023.

| **As of December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Projected benefit obligation | $ 114,260 | $ 127,093 |
| Accumulated benefit obligation | $ 114,260 | $ 127,093 |
| Fair value of plan assets | $ 89,398 | $ 92,320 |

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2024 and 2023.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2024 and 2023 consisted of:

| Years Ended December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Net periodic benefit cost** | | | | |
| Service cost | $ — | $ — | $ 27 | $ 29 |
| Interest cost | 5,619 | 6,108 | 742 | 737 |
| Expected return on plan assets | (6,032) | (5,472) | (195) | (222) |
| Amortization of prior service cost | 102 | 102 | 396 | 427 |
| Amortization of actuarial loss (gain) | 1,497 | 1,536 | 183 | (194) |
| **Net periodic benefit cost** | **$ 1,186** | **$ 2,274** | **$ 1,153** | **$ 777** |
| **Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities** | | | | |
| Amortization of prior service cost | $ (102) | $ (102) | $ (396) | $ (427) |
| Current year actuarial (gain) loss | (4,640) | 1,296 | (1,289) | 2,871 |
| Amortization of actuarial (loss) gain | (1,497) | (1,536) | (183) | 194 |
| **Total recognized in regulatory assets and regulatory liabilities** | **$ (6,239)** | **$ (342)** | **$ (1,868)** | **$ 2,638** |
| **Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities** | **$ (5,053)** | **$ 1,932** | **$ (715)** | **$ 3,415** |

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, 2024 and 2023 consisted of:

| As of December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| Discount rate | 5.33 % | 4.65 % | 5.33 % | 4.65 % |
| Rate of compensation increase | N/A | N/A | N/A | N/A |
| Interest crediting rate | 3.30 % | 3.13 % | 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, 2024 and 2023 consisted of:

| Years Ended December 31, | Pension Benefits 2024 | Pension Benefits 2023 | Postretirement Benefits 2024 | Postretirement Benefits 2023 |
|---|---|---|---|---|
| Discount rate | 4.65 % | 5.17 % | 4.65 % | 5.10 % |
| Expected long-term return on plan assets | 7.50 % | 7.50 % | 7.50 % | 7.50 % |
| Rate of compensation increase | N/A | 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, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| Health care cost trend rate (pre 65/post 65) | 8.90% / 10.60% | 8.10% / 8.60% |
| 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 | 2039 / 2039 | 2031 / 2032 |

***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 $2.6 million to our pension benefits plan in 2025. We expect to contribute $0.2 million to our postretirement benefits plan in 2025.

***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)** | | | |
| 2025 | $ 12,256 | $ 1,402 | $ 75 |
| 2026 | $ 10,903 | $ 1,322 | $ 79 |
| 2027 | $ 10,429 | $ 1,264 | $ 80 |
| 2028 | $ 10,706 | $ 1,284 | $ — |
| 2029 | $ 10,217 | $ 1,222 | $ — |
| 2030-2034 | $ 44,934 | $ 5,465 | $ — |

***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, 2024, by asset category, consisted of:

| | | Fair Value Measurements | | |
|---|---|---|---|---|
| **Asset Category** | **Total** | **(Level 1)** | **(Level 2)** | **(Level 3)** |
| **(Thousands)** | | | | |
| **As of December 31, 2024** | | | | |
| Cash and cash equivalents | $ 3,628 | $ 177 | $ 3,451 | $ — |
| U.S. government securities | 12,489 | 12,489 | — | — |
| Common stocks | 3,807 | 3,807 | — | — |
| Registered investment companies | 7,203 | 7,203 | — | — |
| Corporate bonds | 14,616 | — | 14,616 | — |
| Common collective trusts | 29,268 | — | 29,268 | — |
| Other, principally annuity, fixed income | 76 | — | 76 | — |
| | **$ 71,087** | **$ 23,676** | **$ 47,411** | **$ —** |
| Other investments measured at net asset value | 18,311 | | | |
| **Total** | **$ 89,398** | | | |

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** | | | |

### 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.
- 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, 2024 consisted of:

| | | Fair Value Measurements | | |
|---|---|---|---|---|
| **Asset Category** | **Total** | **(Level 1)** | **(Level 2)** | **(Level 3)** |
| **(Thousands)** | | | | |
| **As of December 31, 2024** | | | | |
| Cash and cash equivalents | $ 127 | $ (1) | $ 128 | $ — |
| U.S. government securities | 40 | 40 | — | — |
| Common stocks | 134 | 134 | — | — |
| Registered investment companies | 241 | 241 | — | — |
| Corporate bonds | 669 | — | 669 | — |
| Common collective trusts | 975 | — | 975 | — |
| Other, principally annuity, fixed income | 3 | — | 3 | — |
| | **$ 2,189** | **$ 414** | **$ 1,775** | **$ —** |
| Other investments measured at net asset value | 571 | | | |
| **Total** | **$ 2,760** | | | |

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 | $ 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** | | | |

### 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.
- 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 Iberdrola common stock as of both December 31, 2024 and 2023.

### Note 14. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2024 and 2023, consisted of:

| **Years Ended December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| Interest and dividend income | $ | 317 | $ | 592 |
| Carrying costs on regulatory assets | | 4,880 | | 1,197 |
| Allowance for funds used during construction | | 883 | | 807 |
| Miscellaneous | | 93 | | 43 |
| **Total other income** | **$** | **6,173** | **$** | **2,639** |
| Pension non-service components | $ | (1,511) | $ | 25 |
| Miscellaneous | | (3,646) | | (2,401) |
| **Total other deductions** | **$** | **(5,157)** | **$** | **(2,376)** |

### 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 $27.8 million and $25.0 million for the years ended December 31, 2024 and 2023, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $1.5 million for 2024 and $1.0 million for 2023. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by SCG to AGR and its subsidiaries was approximately $8.8 million for 2024 and $5.4 million for 2023. 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 $23.1 million at December 31, 2024 and $20.9 million at December 31, 2023, respectively, is mostly payable to UIL Holdings. The balance in accounts receivable from affiliates of $1.2 million at December 31, 2024 and $0.6 million at December 31, 2023, respectively, is mostly receivable from UI.

The balance in notes receivable from affiliates of $41.4 million at December 31, 2024 is receivable from Avangrid. The balance in notes receivable from affiliates of $15.3 million at December 31, 2023, is receivable from Avangrid and NYSEG. Notes receivable from affiliates relate to the Virtual Money Pool Agreement and the CNE and TPS agreement with Avangrid 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 28, 2025, which is the date these consolidated financial statements were available to be issued.

# The United Illuminating Company

## Financial Statements

## As of and for the Years Ended December 31, 2024 and 2023

# The United Illuminating Company

## Index

KPMG LLP
Two Financial Center
60 South Street
Boston, MA 02111

# Independent Auditors' Report

The Shareholder and 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, 2024 and 2023, 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, 2024 and 2023, 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

Boston, Massachusetts
April 11, 2025

## The United Illuminating Company
## Statements of Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Operating Revenues** | $ | **1,340,889** | $ | **1,356,118** |
| **Operating Expenses** | | | | |
| Electricity purchased | | 437,888 | | 545,523 |
| Operations and maintenance | | 509,137 | | 432,461 |
| Depreciation and amortization | | 119,037 | | 114,380 |
| Taxes other than income taxes, net | | 121,127 | | 110,495 |
| **Total Operating Expenses** | | **1,187,189** | | **1,202,859** |
| **Operating Income** | | **153,700** | | **153,259** |
| Other income | | 32,069 | | 23,960 |
| Other deductions | | (6,660) | | (1,868) |
| Earnings from equity method investments | | 2,258 | | 2,975 |
| Interest expense, net of capitalization | | (50,949) | | (41,987) |
| **Income Before Income Tax** | | **130,418** | | **136,339** |
| Income tax expense | | 22,432 | | 23,801 |
| **Net Income** | $ | **107,986** | $ | **112,538** |

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

## The United Illuminating Company
## Statements of Comprehensive Income

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Net Income** | $ | **107,986** | $ | **112,538** |
| **Other Comprehensive Income (Loss)** | | | | |
| Amortization of pension cost for non-qualified plans and current year actuarial gain (loss), net of income tax expense of $261 for 2024 and tax benefit of ($95) for 2023, respectively | | 709 | | (258) |
| **Other Comprehensive Income (Loss)** | | **709** | | **(258)** |
| **Comprehensive Income** | $ | **108,695** | $ | **112,280** |

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

## The United Illuminating Company
## Balance Sheets

| As of December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 1,202 | $ 4,359 |
| Accounts receivable and unbilled revenues, net | 216,630 | 200,295 |
| Accounts receivable from affiliates | 306 | 4,471 |
| Notes receivable from affiliates | 23,000 | — |
| Materials and supplies | 16,011 | 12,046 |
| Derivative assets | 342 | 454 |
| Prepayments and other current assets | 15,487 | 10,387 |
| Income tax receivable | 6,544 | 2,544 |
| Regulatory assets | 142,288 | 132,434 |
| **Total Current Assets** | **421,810** | **366,990** |
| Utility plant, at original cost | 4,096,446 | 3,791,867 |
| Less accumulated depreciation | (1,235,332) | (1,137,053) |
| **Net Utility Plant in Service** | **2,861,114** | **2,654,814** |
| Construction work in progress | 284,497 | 372,242 |
| **Total Utility Plant** | **3,145,611** | **3,027,056** |
| Operating lease right-of-use assets | 11,307 | 11,790 |
| Equity method investments | 75,139 | 78,747 |
| Other property and investments | 20,285 | 16,740 |
| **Regulatory and Other Assets** | | |
| Regulatory assets | 280,424 | 305,644 |
| Derivative assets | 121 | 445 |
| Other | 28,346 | 25,605 |
| **Total Regulatory and Other Assets** | **308,891** | **331,694** |
| **Total Assets** | **$ 3,983,043** | **$ 3,833,017** |

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

## The United Illuminating Company
## Balance Sheets

| As of December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Liabilities** | | | | |
| **Current Liabilities** | | | | |
| Current portion of debt | $ | 99,538 | $ | — |
| Notes payable to affiliates | | — | | 24,400 |
| Accounts payable and accrued liabilities | | 145,671 | | 170,503 |
| Accounts payable to affiliates | | 78,272 | | 71,314 |
| Interest accrued | | 12,095 | | 10,841 |
| Taxes accrued | | 18,433 | | 16,636 |
| Operating lease liabilities | | 623 | | 703 |
| Derivative liabilities | | 14,462 | | 16,777 |
| Other current liabilities | | 55,819 | | 41,712 |
| Regulatory liabilities | | 14,124 | | 13,650 |
| **Total Current Liabilities** | | **439,037** | | **366,536** |
| **Regulatory and Other Liabilities** | | | | |
| Regulatory liabilities | | 331,753 | | 333,670 |
| **Other Non-current Liabilities** | | | | |
| Deferred income taxes | | 465,592 | | 446,803 |
| Pension and other postretirement | | 87,242 | | 119,176 |
| Operating lease liabilities | | 15,201 | | 15,474 |
| Derivative liabilities | | 152 | | 14,050 |
| Environmental remediation costs | | 21,637 | | 24,019 |
| Other | | 31,871 | | 31,417 |
| **Total Regulatory and Other Liabilities** | | **953,448** | | **984,609** |
| Non-current debt | | 1,038,487 | | 1,038,310 |
| **Total Liabilities** | | **2,430,972** | | **2,389,455** |
| **Commitments and Contingencies** | | | | |
| **Common Stock Equity** | | | | |
| Common stock (no par value, 30,000,000 shares authorized and 100 shares outstanding at December 31, 2024 and December 31, 2023) | | 1 | | 1 |
| Additional paid-in capital | | 906,409 | | 906,595 |
| Retained earnings | | 652,641 | | 544,655 |
| Accumulated other comprehensive loss | | (6,980) | | (7,689) |
| **Total Common Stock Equity** | | **1,552,071** | | **1,443,562** |
| **Total Liabilities and Equity** | $ | **3,983,043** | $ | **3,833,017** |

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

# The United Illuminating Company
## Statements of Cash Flows

| Years Ended December 31, | 2024 | 2023 |
|---|---|---|
| (Thousands) | | |
| **Cash Flow from Operating Activities:** | | |
| **Net income** | **$ 107,986** | **$ 112,538** |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 119,037 | 114,380 |
| Regulatory assets/liabilities amortization | 30,910 | (79,700) |
| Regulatory assets/liabilities carrying cost | (11,289) | (4,860) |
| Amortization of debt issuance costs | 555 | 552 |
| Deferred taxes | 8,324 | 27,811 |
| Pension cost | 2,739 | 5,703 |
| Stock-based compensation | 62 | 55 |
| Gain on disposal of assets | (35) | — |
| Earnings from equity method investments | (2,245) | (2,963) |
| Cash distribution from equity method investments | 2,372 | 2,965 |
| Other non-cash Items | (14,772) | (12,394) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable, from affiliates, and unbilled revenues | (12,170) | (33,025) |
| Inventories | (3,965) | (3,666) |
| Accounts payable, to affiliates, and accrued liabilities | (5,835) | (18,446) |
| Taxes accrued | (2,202) | (4,623) |
| Other assets/liabilities | 33,584 | 17,231 |
| Regulatory assets/liabilities | (90,289) | (123,136) |
| **Net Cash Provided by (Used in) Operating Activities** | **162,767** | **(1,578)** |
| **Cash Flow from Investing Activities:** | | |
| Capital expenditures | (231,549) | (218,212) |
| Contributions in aid of construction | 9,375 | 4,829 |
| Notes receivable from affiliates | (23,000) | 82,600 |
| Proceeds from sale of utility plant | 573 | 397 |
| Cash distribution from equity method investments | 3,481 | 3,784 |
| **Net Cash Used in Investing Activities** | **(241,120)** | **(126,602)** |
| **Cash Flow from Financing Activities:** | | |
| Non-current debt issuance | 99,596 | 188,138 |
| Repayments of non-current debt | — | (75,000) |
| Notes payable to affiliates | (24,400) | 24,400 |
| Capital contribution | — | 100,000 |
| Dividends paid | — | (105,000) |
| **Net Cash Provided by Financing Activities** | **75,196** | **132,538** |
| **Net (Decrease) Increase in Cash and Cash Equivalents** | **(3,157)** | **4,358** |
| **Cash and Cash Equivalents, Beginning of Period** | **4,359** | **1** |
| **Cash and Cash Equivalents, End of Period** | **$ 1,202** | **$ 4,359** |

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, 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** |
| Net income | — | — | — | 107,986 | — | 107,986 |
| Other comprehensive income, net of tax | — | — | — | — | 709 | 709 |
| Comprehensive income | | | | | | 108,695 |
| Stock-based compensation | — | — | (186) | — | — | (186) |
| **Balance, December 31, 2024** | **100** | **$ 1** | **$ 906,409** | **$ 652,641** | **$ (6,980)** | **$ 1,552,071** |

(*) 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 345,800 customers as of December 31, 2024 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 wholly-owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

***Agreement and Plan of Merger:*** On May 17, 2024, AGR entered into an Agreement and Plan of Merger (the Merger Agreement) with Iberdrola and Arizona Merger Sub, Inc (Merger Sub). As a result of the consummation of the Merger on December 23, 2024 (closing date), Merger Sub merged with and into Avangrid (the Merger), with Avangrid continuing as the surviving corporation and a wholly-owned subsidiary of Iberdrola. On the closing date, each share of common stock issued and outstanding immediately prior to the closing date (other than common stock owned by the Merger, Merger Sub or any other direct or indirect wholly-owned Subsidiary of the Merger, and in each case not held on behalf of the third parties (collectively, the Excluded Shares)) was converted into a right to receive $35.75 per share of common stock in cash, without interest.

On the closing date, (i) all shares of common stock ceased to be outstanding, were cancelled and ceased to exist and (ii) each Excluded Share ceased to be outstanding and was cancelled without payment of any consideration and ceased to exist. As a result of the consummation of the Merger on December 23, 2024, Iberdrola became the direct owner of 100 shares of common stock of Avangrid which represents the only outstanding capital of the Company. On the closing date, the New York Stock Exchange (NYSE) filed with the Securities and Exchange Commission (the SEC) a notification of removal from listing on Form 25 in order to delist the common stock from the NYSE and deregister the common stock under Section 12(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Following the effectiveness of the Form 25, on January 2, 2025, Avangrid filed with the SEC a Form 15 requesting the termination of registration of the common stock under Section 12(g) of the Exchange Act and the suspension of reporting obligations under Section 13 and 15(d) of the Exchange Act with respect to the common stock.

***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 2.7% of average depreciable property for 2024 and 2.8% of average depreciable property for 2023. 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 $314.5 million as of December 31, 2024, and $312.5 million as of December 31, 2023. Depreciation expense was $100.5 million in 2024 and $98.1 million in 2023. Amortization of capitalized software was $18.6 million in 2024 and $16.2 million in 2023.

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) | 2024 | 2023 |
|---|---|---|---|
| (Thousands) | | | |
| Distribution | 5-75 | $ 2,221,057 | $ 2,165,258 |
| Transmission | 5-60 | 1,370,091 | 1,149,793 |
| Other | 1-58 | 505,298 | 476,816 |
| **Total Utility Plant in Service** | | **4,096,446** | **3,791,867** |
| Total accumulated depreciation | | (1,235,332) | (1,137,053) |
| **Total Net Utility Plant in Service** | | **2,861,114** | **2,654,814** |
| Construction work in progress | | 284,497 | 372,242 |
| **Total Utility Plant** | | **$ 3,145,611** | **$ 3,027,056** |

***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:

| (Thousands) | 2024 | 2023 |
|---|---|---|
| **Cash paid during the year ended December 31:** | | |
| Interest, net of amounts capitalized | $ 45,563 | $ 32,600 |
| Income taxes paid, net | $ 20,057 | $ 7,362 |

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $7.7 million in 2024 and $6.0 million in 2023. Accrued liabilities for utility plant additions were $51.3 million as of December 31, 2024 and $62.2 million as of December 31, 2023.

***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 $72.4 million for 2024 and $57.0 million for 2023, and are shown net of an allowance for credit losses at December 31 of $14.2 million for 2024 and $15.0 million for 2023. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $64.1 million in 2024 and $51.3 million in 2023.

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.

***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 $6.5 million and $2.5 million at December 31, 2024 and 2023, 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. 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 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, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

There have been no new accounting pronouncements adopted as of and for the year ended December 31, 2024 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 standard is required to be adopted by private entities for the annual periods beginning after December 15, 2025. Early adoption is permitted. The two primary enhancements relate to disaggregation of the annual effective tax rate reconciliation and income taxes paid disclosures. 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 61% of our employees are covered by a collective bargaining agreement. All collective bargaining agreements 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 had been operating under the 2019 approved rate schedules until September 1, 2023.

On September 9, 2022, UI filed a distribution revenue requirement case. UI's filing proposed a three-year rate plan commencing September 1, 2023 through August 31, 2026. 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 resulted 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. Given the expiration of the rate plan, UI had been operating under the 2023 approved rate schedules. 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. A decision was issued by the Court on March 13, 2025, which largely upheld PURA's Final Decision. The Company filed an appeal of the trial Court's decision on March 28, 2025. We cannot predict the outcome of this matter.

On November 12, 2024, UI filed an application to adjust its rates and charges which proposes to amend UI's existing rate schedules effective November 1, 2025, in order to address a significant deficiency in distribution-related operating revenues. More specifically, the UI application proposes a change in base distribution rates to be implemented in the rate year beginning November 1, 2025, with proposed rates designed to provide incremental operating revenues of approximately $105 million. UI's application also includes several measures to moderate the impact of the proposed rate update for customers, including, a low-income discount rate to provide rate relief to UI's disadvantaged customers, as well as proposing to continue an economic development rate to support continued commercial growth in UI's service territory. We cannot predict the outcome of this matter.

**Connecticut Energy Legislation**

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. We will continue to review the requirements of the program for the next legislative session.

**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, 2024, UI has wholesale power supply agreements in place for 100% of the first half of 2025, and 50% of the second half of 2025. 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 2025.

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, 2024, UI would have had to post collateral of approximately $31.3 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.

**Notes to Financial Statements**

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 (Complaint I) 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 of 9.2%. UI is a NETO with assets and service rates that are governed by the OATT and will thereby be affected by any FERC order resulting from the filed complaint.

On December 26, 2012, a second related complaint (Complaint II) for a subsequent rate period was filed requesting the ROE be reduced to 8.7%.  On July 31, 2014, a third related complaint (Complaint III) was filed for a subsequent rate period requesting the ROE be reduced to 8.84%. On April 29, 2016, a fourth complaint (Compliant IV) was filed for a rate period subsequent to prior complaints requesting the base ROE be 8.61% and ROE cap be 11.24%.

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 $9.3 million as of December 31, 2024, which has not changed since December 31, 2023, 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. On October 17, 2024, FERC issued its order on remand in the MISO ROE complaint proceedings. In this order, FERC reduced the MISO transmission owners' base ROE to 9.98% by eliminating the risk premium model from the ROE calculation, consistent with the DC Circuit's remand, and affirmed the refunds ordered in Opinion 569 (which were not addressed on appeal by the DC Circuit). On November 13, 2024, the NETOs submitted a supplemental brief into the NETO ROE case. The supplemental brief primarily addresses distinctions between the MISO transmission owners' and the NETOs' ROE cases. We cannot predict the potential impact that 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 28, 2024, seeking approval of its 2025 revenue requirements for the period commencing January 1, 2025 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 $40.4 million. While the company was required to file its application consistent with PURA's order in the 2023 decision, GenConn has also presented a method that appropriately calculates revenue requirements of $45.8 million and has reserved the right to update revenue requirements following outcomes of legal appeals of the last 3 decisions. A Final Decision was issued on December 18, 2024 approving revenue requirements of $40.4 million. The company plans to appeal the 2025 revenue requirements decision. The company cannot predict the outcome of this matter.

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. On February 27, 2024, the Supreme Court issued an opinion in favor of PURA.

**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.

**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.

On October 29, 2024, the Supreme Court remanded the appeal to PURA with an order to vacate its ROE penalty and to recalculate its minor accident fine. The Court did not modify the Trial Court's decision to uphold the $1 million fine for the emergency storm response performance. On December 11, 2024, PURA entered an order vacating the ROE penalty and reducing the minor accident fine from $61,000 to $2,500.

**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 $203.6 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.

Regulatory assets at December 31, 2024 and 2023 consisted of:

| **As of December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Contracts for differences | $ 14,151 | $ 29,928 |
| COVID-19 cost recovery | 6,713 | 8,550 |
| Deferred transmission expense | 2,907 | 1,097 |
| Environmental remediation costs | 13,838 | 6,916 |
| Excess generation service charge | 47,346 | 52,401 |
| Non-bypassable charges | 24,545 | 14,421 |
| Pension and other postretirement benefit plans | 72,027 | 87,589 |
| Pension and other postretirement benefits cost deferrals | 18,983 | 21,026 |
| Revenue decoupling mechanism | — | 10,399 |
| Storm costs | 26,573 | 25,384 |
| System benefit charge | 44,741 | 29,165 |
| Unamortized losses on reacquired debt | 3,957 | 4,456 |
| Unfunded future income taxes | 129,968 | 124,727 |
| Other | 16,963 | 22,019 |
| **Total regulatory assets** | **422,712** | **438,078** |
| Less: current portion | 142,288 | 132,434 |
| **Total non-current regulatory assets** | **$ 280,424** | **$ 305,644** |

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.

Regulatory liabilities at December 31, 2024 and 2023 consisted of:

| **As of December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| 2017 Tax Act | $ | 201,764 | $ | 206,288 |
| Accrued removal obligations | | 79,809 | | 80,709 |
| Accumulated deferred investment tax credits | | 9,169 | | 9,898 |
| Conservation and load management | | 4,668 | | 6,176 |
| Middletown/Norwalk local transmission network service collections | | 15,096 | | 15,669 |
| Pension and other postretirement benefit plans | | 16,267 | | 12,619 |
| Pension and other postretirement benefits cost deferrals | | 1,423 | | 1,974 |
| Revenue decoupling mechanism | | 2,879 | | — |
| Rate refund - FERC ROE proceeding | | 9,254 | | 8,507 |
| Other | | 5,548 | | 5,480 |
| **Total regulatory liabilities** | | **345,877** | | **347,320** |
| Less: current portion | | 14,124 | | 13,650 |
| **Total non-current regulatory liabilities** | **$** | **331,753** | **$** | **333,670** |

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.

Conservation and load management represents the difference between UI's costs for customer conservation measures and the amounts collected in rates for those costs.

Middletown/Norwalk local transmission network service collections represents allowance for funds used during construction of the Middletown/Norwalk transmission line, which is being amortized over the useful life of the project.

Pension and other postretirement 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.

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

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, 2024 and 2023 are as follows:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Regulated operations – electricity | $ 1,305,682 | $ 1,307,393 |
| Other (a) | 16,517 | 8,811 |
| **Revenue from contracts with customers** | **1,322,199** | **1,316,204** |
| Leasing revenue | 6,511 | 6,399 |
| Alternative revenue programs | 5,485 | 26,356 |
| Other revenue | 6,694 | 7,159 |
| **Total operating revenues** | **$ 1,340,889** | **$ 1,356,118** |

(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, 2024 and 2023 consisted of:

| **Years Ended December 31,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| **Current** | | |
| Federal | $ 14,757 | $ (2,926) |
| State | 81 | (354) |
| **Current taxes charged to expense (benefit)** | **14,838** | **(3,280)** |
| **Deferred** | | |
| Federal | 5,262 | 24,726 |
| State | 3,062 | 3,085 |
| **Deferred taxes charged to expense** | **8,324** | **27,811** |
| Investment tax credits | (730) | (730) |
| **Total Income Tax Expense** | **$ 22,432** | **$ 23,801** |

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, 2024 and 2023 consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Tax expense at federal statutory rate | $ | 27,388 | $ | 28,631 |
| Depreciation/amortization and other plant differences not normalized | | (2,595) | | (1,538) |
| State taxes net of federal benefit | | 2,483 | | 2,158 |
| Investment tax credit amortization | | (730) | | (730) |
| Excess ADIT amortization | | (3,306) | | (4,731) |
| Other, net | | (808) | | 11 |
| **Total Income Tax Expense** | **$** | **22,432** | **$** | **23,801** |

Income tax expense for the year ended December 31, 2024 was $5 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 17.2%. 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 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%.

Deferred tax assets and liabilities as of December 31, 2024 and 2023 consisted of:

| December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Non-current Deferred Income Tax Liabilities (Assets)** | | | | |
| Property related | $ | 467,938 | $ | 442,597 |
| Unfunded future income taxes | | 34,922 | | 33,510 |
| Federal and state tax credits | | (16,313) | | (4,051) |
| Investment in GenConn | | 31,492 | | 31,564 |
| Postretirement benefits | | (7,790) | | (10,693) |
| Regulatory liability due to "Tax Cuts and Jobs Act" | | (54,325) | | (55,543) |
| Other | | 9,668 | | 9,419 |
| **Total Non-current Deferred Income Tax Liabilities** | **$** | **465,592** | **$** | **446,803** |
| Deferred tax assets | $ | 78,428 | $ | 70,287 |
| Deferred tax liabilities | | 544,020 | | 517,090 |
| **Net Accumulated Deferred Income Tax Liabilities** | **$** | **465,592** | **$** | **446,803** |

As of December 31, 2024, UI had $16.3 million of state tax credit carry forwards with no valuation allowance offset. As of December 31, 2023, UI had $4.1 million of gross state tax credit carry forwards with no valuation allowance offset. The state tax credit carry forwards will begin to expire in 2028.

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, 2024 and 2023, 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, 2024 and 2023.

**Note 6. Non-current Debt**

Long-term debt as of December 31, 2024 and 2023 consisted of:

| As of December 31, | | 2024 | | 2023 | |
|---|---|---|---|---|---|
| (Thousands) | Maturity Dates | Balances | Interest Rates | Balances | Interest Rates |
| Senior unsecured notes | 2025 - 2049 | $ 1,144,460 | 2.02% - 6.51% | $ 1,044,460 | 2.02% - 6.51% |
| Unamortized debt issuance costs and discount | | (6,435) | | (6,150) | |
| **Total Debt** | | **1,138,025** | | **1,038,310** | |
| Less: debt due within one year, included in current liabilities | | 99,538 | | — | |
| **Total Non-current Debt** | | **$ 1,038,487** | | **$ 1,038,310** | |

On August 15, 2024, UI issued $100 million aggregate principal amount of unsecured notes maturing in 2039 at an interest rate of 5.67%.

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.

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

| 2025 | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| $ 99,538 | $ — | $ — | $ 100,000 | $ — | $ 199,538 |

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2024 and 2023.

**Note 7. Bank Loans and Other Borrowings**

UI had no short-term debt outstanding at December 31, 2024 and $24.4 million of short-term debt outstanding at December 31, 2023. 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, 2024 and December 31, 2023.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. UI had no debt outstanding under this agreement at December 31, 2024 and $24.4 million of debt outstanding under this agreement at December 31, 2023.

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. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates. 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, 2024 and December 31, 2023.

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 0.42 to 1.00 at December 31, 2024. We are not in default as of December 31, 2024.

**Note 8. Preferred Stock**

At December 31, 2024, 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 39 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, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Lease cost** | | | | |
| Operating lease cost | $ | 3,917 | $ | 3,415 |
| Short-term lease cost | | 173 | | 172 |
| Variable lease cost | | 127 | | 127 |
| **Total lease cost** | **$** | **4,217** | **$** | **3,714** |

Balance sheet and other information for the years ended December 31, 2024 and 2023 was as follows:

| As of December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands, except lease term and discount rate) | | | | |
| **Operating Leases** | | | | |
| Operating lease right-of-use assets | $ | 11,307 | $ | 11,790 |
| | | | | |
| Operating lease liabilities, current | | 623 | | 703 |
| Operating lease liabilities, long-term | | 15,201 | | 15,474 |
| Total operating lease liabilities | $ | 15,824 | $ | 16,177 |
| | | | | |
| **Weighted-average Remaining Lease Term (years)** | | | | |
| Operating leases | | 19.61 | | 20.49 |
| **Weighted-average Discount Rate** | | | | |
| Operating leases | | 3.76% | | 3.72% |

For the years ended December 31, 2024 and 2023, supplemental cash flow information related to leases was as follows:

| For the Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | | | |
| Operating cash flows from operating leases | $ | 1,098 | $ | 1,184 |
| | | | | |
| Right-of-use assets obtained in exchange for lease obligations: | | | | |
| Operating leases | $ | 250 | $ | 115 |

As of December 31, 2024, maturities of lease liabilities were as follows:

| (Thousands) | | Operating Leases |
|---|---|---|
| **Year ending December 31,** | | |
| 2025 | $ | 1,057 |
| 2026 | | 1,139 |
| 2027 | | 3,318 |
| 2028 | | 853 |
| 2029 | | 859 |
| Thereafter | | 16,666 |
| **Total lease payments** | | **23,892** |
| Less: imputed interest | | (8,068) |
| **Total** | **$** | **15,824** |

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 $19.9 million and $19.4 million as of December 31, 2024 and 2023, respectively. 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, 2024 and December 31, 2023, the amount reserved for this property was $14.6 million and $8.0 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, 2024 and 2023.

Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2151.

**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, 2024, UI has recorded a gross derivative asset of $0.5 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $14.2 million, a gross derivative liability of $14.6 million ($14.0 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, 2023, UI had 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.

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets, for the years ended December 31, 2024 and 2023, respectively, were as follows:

| | Years Ended December 31, | |
|---|---|---|
| | 2024 | 2023 |
| **(Thousands)** | | |
| Derivative assets | $ (436) | $ (447) |
| Derivative liabilities | $ 16,213 | $ 15,121 |

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

The estimated fair value of debt amounted to $1,098 million as of December 31, 2024 and $1,016 million as of December 31, 2023. 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, 2024 and December 31, 2023, consisted of:

| As of December 31, 2024 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| **Derivative assets** | | | | |
| Contracts for differences | $ — | $ — | $ 463 | $ 463 |
| **Equity investments with readily determinable fair values** | | | | |
| Supplemental retirement benefit trust life insurance policies | — | 20,026 | — | 20,026 |
| **Total** | **$ —** | **$ 20,026** | **$ 463** | **$ 20,489** |
| **Derivative liabilities** | | | | |
| Contracts for differences | $ — | $ — | $ (14,614) | $ (14,614) |
| **Total** | **$ —** | **$ —** | **$ (14,614)** | **$ (14,614)** |

| 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)** |

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2024 and 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 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.

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, 2024 | Range at December 31, 2023 |
|---|---|---|
| Risk of non-performance | 0.46% - 0.48% | 0.42% - 0.52% |
| Discount rate | 4.16% - 4.25% | 3.84% - 4.01% |
| Forward pricing ($ per MW) | $2.59 - $2.61 | $2.00 - $2.61 |

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2024 and 2023, respectively, is as follows:

| Years Ended December 31, | | 2024 | 2023 |
|---|---|---|---|
| (Thousands) | | | |
| **Beginning balance** | $ | (29,928) $ | (44,602) |
| Unrealized gains, net | | 15,777 | 14,674 |
| **Ending balance** | **$** | **(14,151) $** | **(29,928)** |

## 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 $9.4 million for 2024 and $8.1 million for 2023.

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 $9.7 million and $10.6 million at December 31, 2024 and 2023, 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, 2024 and 2023 consisted of:

| As of December 31, | Pension Benefits 2024 | 2023 | Postretirement Benefits 2024 | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| **Change in benefit obligation** | | | | |
| **Benefit obligation as of January 1,** | **$ 400,738** | **$ 390,971** | **$ 47,850** | **$ 40,885** |
| Service cost | — | — | 292 | 267 |
| Interest cost | 17,937 | 19,462 | 2,129 | 2,019 |
| Actuarial loss (gain) | (21,352) | 21,898 | (1,780) | 9,935 |
| Benefits paid | (31,039) | (31,593) | (4,433) | (5,256) |
| **Benefit obligation as of December 31,** | **$ 366,284** | **$ 400,738** | **$ 44,058** | **$ 47,850** |
| **Change in plan assets** | | | | |
| **Fair value of plan assets at January 1,** | **$ 295,039** | **$ 279,538** | **$ 34,373** | **$ 30,885** |
| Actual return on plan assets | 9,407 | 36,864 | 5,098 | 5,202 |
| Employer contributions | 11,384 | 10,230 | 3,271 | 3,542 |
| Benefits paid | (31,039) | (31,593) | (4,433) | (5,256) |
| **Fair value of plan assets at December 31,** | **$ 284,791** | **$ 295,039** | **$ 38,309** | **$ 34,373** |
| **Funded status at December 31,** | **$ (81,493)** | **$ (105,699)** | **$ (5,749)** | **$ (13,477)** |

During 2024, the pension benefit obligation had an actuarial gain of $21.4 million, primarily due to a $25.9 million gain from increases in discount rates. During 2024, the postretirement benefit obligation had an actuarial gain of $1.8 million, primarily due to a $2.8 million gain from increases in discount rates.

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.

Amounts recognized as of December 31, 2024 and 2023 consisted of:

| As of December 31, | Pension Benefits 2024 | 2023 | Postretirement Benefits 2024 | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Non-current liabilities | $ (81,493) | $ (105,699) | $ (5,749) | $ (13,477) |

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, 2024 and 2023 consisted of:

| Years Ended December 31, | Pension Benefits 2024 | 2023 | Postretirement Benefits 2024 | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Net loss (gain) | $ 68,979 | $ 83,353 | $ (10,670) | $ (7,029) |
| Prior service cost | $ 3,048 | $ 4,236 | $ — | $ — |

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $366.3 million and $400.7 million as of December 31, 2024 and 2023, respectively. Our postretirement benefits were partially funded at December 31, 2024 and 2023.

The PBO and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2024 and 2023. 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,** | **2024** | **2023** |
|---|---|---|
| **(Thousands)** | | |
| Projected benefit obligation | $ 366,284 | $ 400,738 |
| Accumulated benefit obligation | $ 366,284 | $ 400,738 |
| Fair value of plan assets | $ 284,791 | $ 295,039 |

As of December 31, 2024 and 2023, 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, 2024 and 2023 consisted of:

| | **Pension Benefits** | | **Postretirement Benefits** | |
|---|---|---|---|---|
| **For the years ended December 31,** | **2024** | **2023** | **2024** | **2023** |
| **(Thousands)** | | | | |
| **Net Periodic Benefit Cost:** | | | | |
| Service cost | $ — | $ — | $ 292 | $ 267 |
| Interest cost | 17,937 | 19,462 | 2,129 | 2,019 |
| Expected return on plan assets | (20,159) | (18,645) | (2,234) | (2,162) |
| Amortization of prior service cost (credit) | 1,188 | 1,188 | — | (1,056) |
| Amortization of actuarial loss (gain) | 3,773 | 3,698 | (1,004) | (2,344) |
| **Net Periodic Benefit Cost** | **$ 2,739** | **$ 5,703** | **$ (817)** | **$ (3,276)** |
| **Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:** | | | | |
| Amortization of prior service (cost) benefit | $ (1,188) | $ (1,188) | $ — | $ 1,056 |
| Current year actuarial loss (gain) | (10,600) | 3,679 | (4,645) | 6,895 |
| Amortization of actuarial (loss) gain | (3,773) | (3,698) | 1,004 | 2,344 |
| **Total Other Changes** | **$ (15,561)** | **$ (1,207)** | **$ (3,641)** | **$ 10,295** |
| **Total Recognized** | **$ (12,822)** | **$ 4,496** | **$ (4,458)** | **$ 7,019** |

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, 2024 and 2023 consisted of:

| As of December 31, | Pension Benefits 2024 | 2023 | Postretirement Benefits 2024 | 2023 |
|---|---|---|---|---|
| Discount rate | 5.41% | 4.69% | 5.33% | 4.65% |
| 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, 2024 and 2023 consisted of:

| Years Ended December 31, | Pension Benefits 2024 | 2023 | Postretirement Benefits 2024 | 2023 |
|---|---|---|---|---|
| Discount rate | 4.69% | 5.21% | 4.65% | 5.17% |
| Expected long-term return on plan assets | 7.50% | 7.50% | 6.50% | 7.00% |
| Rate of compensation increase | N/A | 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, 2024 and 2023 consisted of:

| As of December 31, | 2024 | 2023 |
|---|---|---|
| Health care cost trend rate assumed for next year | 8.90% / 6.20% | 8.10% / 6.20% |
| 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 | 2039/2032 | 2031/2028 |

### 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 $8.9 million to our pension plan during 2025. We expect to contribute $2.6 million to our other postretirement benefit plans during 2025.

### 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, 2024 consisted of:

| (Thousands) | | Pension Benefits | | Postretirement Benefits | | Medicare Act Subsidy Receipts |
|---|---|---|---|---|---|---|
| 2025 | $ | 35,891 | $ | 4,122 | $ | — |
| 2026 | $ | 33,173 | $ | 4,041 | $ | — |
| 2027 | $ | 32,933 | $ | 3,780 | $ | — |
| 2028 | $ | 31,855 | $ | 3,729 | $ | — |
| 2029 | $ | 31,774 | $ | 3,557 | $ | — |
| 2030 - 2034 | $ | 139,164 | $ | 16,449 | $ | — |

**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, 2024, consisted of:

| As of December 31, 2024 | Fair Value Measurements | | | |
|---|---|---|---|---|
| (Thousands) | Total | Level 1 | Level 2 | Level 3 |
| **Asset Category** | | | | |
| Cash and cash equivalents | $ 11,875 | $ 562 | $ 11,313 | $ — |
| U.S. government securities | 38,860 | 38,860 | — | — |
| Common stocks | 12,177 | 12,177 | — | — |
| Registered investment companies | 23,037 | 23,037 | — | — |
| Corporate bonds | 46,727 | — | 46,727 | — |
| Common collective trusts | 93,633 | — | 93,633 | — |
| Other, principally annuity, fixed income | 243 | — | 243 | — |
| | **$ 226,552** | **$ 74,636** | **$ 151,916** | **$ —** |
| Other investments measured at net asset value | 58,239 | | | |
| **Total** | **$ 284,791** | | | |

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** | | | |

### 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, 2024, consisted of:

| **As of December 31, 2024** | | **Fair Value Measurements** | | |
|---|---|---|---|---|
| **(Thousands)** | **Total** | **Level 1** | **Level 2** | **Level 3** |
| **Asset Category** | | | | |
| Cash and cash equivalents | $ 871 | $ — | $ 871 | $ — |
| Registered investment companies | 37,438 | 37,438 | — | — |
| **Total** | **$ 38,309** | **$ 37,438** | **$ 871** | **$ —** |

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 | $ 168 | $ — | $ 168 | $ — |
| Registered investment companies | 34,205 | 34,205 | — | — |
| **Total** | **$ 34,373** | **$ 34,205** | **$ 168** | **$ —** |

### 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 Iberdrola common stock as of both December 31, 2024 and 2023.

### 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 $75.1 million and $78.7 million as of December 31, 2024 and December 31, 2023, respectively.

UI's pre-tax income from its equity investment in GenConn was $2.3 million and $3.0 million for the years ended December 31, 2024 and 2023, 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 $5.9 million and $6.7 million during the years ended December 31, 2024 and 2023, respectively.

The following represents summarized financial information of GenConn as of and for the years ended December 31, 2024 and 2023, respectively:

| **Years Ended December 31,** | | **2024** | | **2023** |
|---|---|---|---|---|
| **(Thousands)** | | | | |
| Current assets | $ | 42,984 | $ | 39,293 |
| Non-current assets | $ | 277,086 | $ | 294,235 |
| Current liabilities | $ | 16,124 | $ | 14,559 |
| Non-current liabilities | $ | 153,864 | $ | 161,672 |
| Operating revenues | $ | 46,968 | $ | 50,923 |
| Income | $ | 4,489 | $ | 5,926 |

### Note 15. Other Income and Other Deductions

Other income and other deductions for the years ended December 31, 2024 and 2023, respectively, consisted of:

| Years Ended December 31, | | 2024 | | 2023 |
|---|---|---|---|---|
| (Thousands) | | | | |
| Interest and dividends income | $ | 5,022 | $ | 6,299 |
| Allowance for funds used during construction | | 12,973 | | 12,911 |
| Carrying costs on regulatory assets | | 13,982 | | 4,677 |
| Miscellaneous | | 92 | | 73 |
| **Total other income** | **$** | **32,069** | **$** | **23,960** |
| Pension non-service components | $ | (2,131) | $ | 586 |
| Miscellaneous | | (4,529) | | (2,454) |
| **Total other deductions** | **$** | **(6,660)** | **$** | **(1,868)** |

## 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 $89.3 million and $81.4 million for the years ended December 31, 2024 and 2023, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $8.8 million in 2024 and $8.9 million in 2023, 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 $15.4 million in 2024 and $10.9 million in 2023. 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 $78.3 million at December 31, 2024 and $71.3 million at December 31, 2023 is primarily due to UIL Holdings. The balance in accounts receivable from affiliates of $0.3 million at December 31, 2024 is primarily receivable from various companies, and the balance of accounts receivable from affiliates of $4.5 million at December 31, 2023 is primarily receivable from Avangrid Management Company.

The balance in notes receivable from affiliates of $23.0 million at December 31, 2024 is receivable from CMP. There were no notes receivable from affiliates at December 31, 2023. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

## Note 17. Subsequent Events

The company has performed a review of subsequent events through April 11, 2025, which is the date these financial statements were available to be issued.