# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**WASHINGTON, D.C. 20549**

# FORM 10-Q

**(Mark One)**

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended June 30, 2025**
**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from to**

**Commission File No. 333-212006**

**TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.**
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Colorado** | **84-0464189** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. employer identification number) |
| **1100 West 116th Avenue** | |
| **Westminster , Colorado** | **80234** |
| (Address of principal executive offices) | (Zip Code) |

**(303) 452-6111**
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. **Yes** ☐ **No** ☒ (Note: The registrant is not subject to the filing requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), but voluntarily files reports with the Securities and Exchange Commission).

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). **Yes** ☒ **No** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. **Large accelerated filer** ☐ **Accelerated filer** ☐

**Non-accelerated Filer** ☒ **Smaller reporting company** ☐ **Emerging growth company** ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). **Yes** ☐ **No** ☒

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Trading Symbol(s) | Name of each exchange on which registered |
|---|---|---|
| None | None | None |

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. **The registrant is a membership corporation and has no authorized or outstanding equity securities.**

# TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
# INDEX TO QUARTERLY REPORT ON FORM 10-Q
# FOR THE QUARTER ENDED JUNE 30, 2025

## GLOSSARY

The following abbreviations and acronyms used in this quarterly report on Form 10-Q are defined below:

| Abbreviations or Acronyms | Definition |
|---|---|
| 2022 Revolving Credit Agreement | Amended and Restated Credit Agreement, dated as of April 25, 2022, between us and CFC, as administrative agent |
| 2023 ERP | our 2023 Electric Resource Plan filed with the COPUC |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| Basin | Basin Electric Power Cooperative |
| Board | Board of Directors |
| BYOR | Bring Your Own Resource |
| CFC | National Rural Utilities Cooperative Finance Corporation |
| CoBank | CoBank, ACB |
| Colowyo Coal | Colowyo Coal Company L.P., a subsidiary of ours |
| COPUC | Colorado Public Utilities Commission |
| D.C. Circuit Court of Appeals | United States Court of Appeals for the District of Columbia Circuit |
| DSR | Debt Service Ratio (as defined in our Master Indenture) |
| ECR | Equity to Capitalization Ratio (as defined in our Master Indenture) |
| EPA | Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| Fitch | Fitch Ratings Inc. |
| FPA | Federal Power Act, as amended |
| GAAP | Accounting principles generally accepted in the United States |
| IRA | Inflation Reduction Act of 2022 |
| kWh | kilowatt hour |
| LPEA | La Plata Electric Association, Inc. |
| Master Indenture | Master First Mortgage Indenture, Deed of Trust and Security Agreement, dated effective as of December 15, 1999, between us and U.S. Bank Trust Company, National Association, as successor trustee |
| MBPP | Missouri Basin Power Project |
| Members | our Utility Members and Non-Utility Members |
| MPEI | Mountain Parks Electric, Inc. |
| Moody’s | Moody’s Investors Services, Inc. |
| MW | megawatt |
| MWh | megawatt hour |
| Non-Utility Members | our non-utility members |
| NRPPD | Northwest Rural Public Power District |
| New ERA Program | USDA's Empowering Rural America Program |
| OATT | Open Access Transmission Tariff |
| Renewable Revolving Credit Agreement | Renewable Revolving Credit Agreement, dated as of June 18, 2025, between us and CFC, as administrative agent |
| RUS | Rural Utilities Service |
| S&P | S & P Global Ratings |
| SEC | Securities and Exchange Commission |
| Springerville Partnership | Springerville Unit 3 Partnership LP, a subsidiary of ours |
| Springerville Unit 3 | Springerville Generating Station Unit 3 |
| Term SOFR | the implied rate on the future movement in the Secured Overnight Financing Rate (or "SOFR") over a future reference period |

| | |
|---|---|
| Tri-State, We, Our, Us, the Association | Tri-State Generation and Transmission Association, Inc. |
| United Power | United Power, Inc. |
| USDA | United States Department of Agriculture |
| Utility Members | our electric distribution member systems |

## FORWARD-LOOKING STATEMENTS

This quarterly report on Form 10-Q contains "forward-looking statements." All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as the timing of various regulatory and other actions, future capital expenditures, future resources and generation portfolio, future use of deferred revenue, business strategy, member withdraws and development, construction, operation, or closure of facilities (often, but not always, identified through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "forecast," "projection," "target" and "outlook") are forward-looking statements.

Although we believe that in making these forward-looking statements our expectations are based on reasonable assumptions, any forward-looking statement involves uncertainties and there are important factors that could cause actual results to differ materially from those expressed or implied by these forward-looking statements.

# PART I. FINANCIAL INFORMATION
## Item 1. Financial Statements
## Tri-State Generation and Transmission Association, Inc.
## Consolidated Statements of Financial Position (Unaudited)
*(dollars in thousands)*

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| **ASSETS** | | |
| **Property, plant and equipment** | | |
| Electric plant | | |
| In service | $ 5,813,087 | $ 5,701,182 |
| Construction work in progress | 424,029 | 368,473 |
| Total electric plant | **6,237,116** | **6,069,655** |
| Less allowances for depreciation and amortization | (2,901,720) | (2,838,877) |
| Net electric plant | **3,335,396** | **3,230,778** |
| Other plant | 958,438 | 958,993 |
| Less allowances for depreciation, amortization and depletion | (822,756) | (770,270) |
| Net other plant | **135,682** | **188,723** |
| Total property, plant and equipment | **3,471,078** | **3,419,501** |
| **Other assets and investments** | | |
| Investments in other associations | 190,802 | 192,680 |
| Investments in and advances to coal mines | 1,726 | 1,711 |
| Restricted cash and investments | 2,307 | 3,436 |
| Intangible assets, net | 33,766 | 39,556 |
| Other noncurrent assets | 14,119 | 18,407 |
| Total other assets and investments | **242,720** | **255,790** |
| **Current assets** | | |
| Cash and cash equivalents | 181,507 | 229,357 |
| Restricted cash and investments | 1,266 | 744 |
| Deposits and advances | 35,080 | 38,180 |
| Accounts receivable—Utility Members | 95,565 | 85,450 |
| Other accounts receivable | 24,317 | 28,727 |
| Coal inventory | 107,256 | 95,511 |
| Materials and supplies | 116,720 | 110,775 |
| Total current assets | **561,711** | **588,744** |
| **Deferred charges** | | |
| Regulatory assets | 801,455 | 816,541 |
| Other | 60,699 | 51,735 |
| Total deferred charges | **862,154** | **868,276** |
| **Total assets** | **$ 5,137,663** | **$ 5,132,311** |
| **EQUITY AND LIABILITIES** | | |
| **Capitalization** | | |
| Patronage capital equity | $ 898,371 | $ 912,922 |
| Accumulated other comprehensive loss | 1,206 | 965 |
| Noncontrolling interest | 130,330 | 130,498 |
| Total equity | **1,029,907** | **1,044,385** |
| Long-term debt | 2,870,023 | 2,857,346 |
| Total capitalization | **3,899,930** | **3,901,731** |
| **Current liabilities** | | |
| Utility Member advances | 5,024 | 5,128 |
| Accounts payable | 172,758 | 158,176 |
| Short-term borrowings | 44,754 | 100 |
| Accrued expenses | 28,879 | 42,705 |
| Current asset retirement and environmental remediation obligations | 72,670 | 28,451 |
| Accrued interest | 22,751 | 21,454 |
| Accrued property taxes | 18,465 | 31,363 |
| Current maturities of long-term debt | 78,944 | 88,658 |
| Total current liabilities | **444,245** | **376,035** |
| **Deferred credits and other liabilities** | | |
| Regulatory liabilities | 490,672 | 497,028 |
| Deferred income tax liability | 12,217 | 12,217 |
| Asset retirement and environmental remediation obligations | 199,701 | 243,440 |
| Other | 81,756 | 93,058 |
| Total deferred credits and other liabilities | **784,346** | **845,743** |
| **Accumulated postretirement benefit and postemployment obligations** | 9,142 | 8,802 |
| **Total equity and liabilities** | **$ 5,137,663** | **$ 5,132,311** |

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

**Tri-State Generation and Transmission Association, Inc.**
**Consolidated Statements of Operations** (Unaudited)
*(dollars in thousands)*

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2025** | **2024** | **2025** | **2024** |
| **Operating revenues** | | | | |
| Utility Member electric sales | $ 257,649 | $ 258,286 | $ 513,649 | $ 554,112 |
| Non-member electric sales | 44,497 | 38,768 | 92,903 | 74,387 |
| Rate stabilization | 43,183 | 16,901 | 88,126 | 16,901 |
| Provision for rate refunds | 5,273 | — | 2,719 | — |
| Other | 39,525 | 23,544 | 67,930 | 43,648 |
| | **390,127** | **337,499** | **765,327** | **689,048** |
| **Operating expenses** | | | | |
| Purchased power | 110,405 | 98,840 | 207,549 | 191,910 |
| Fuel | 36,543 | 32,208 | 88,343 | 108,548 |
| Production | 37,686 | 47,057 | 74,180 | 89,183 |
| Transmission | 41,869 | 44,964 | 85,959 | 92,522 |
| General and administrative | 39,977 | 23,830 | 79,278 | 45,563 |
| Depreciation, amortization and depletion | 71,154 | 44,152 | 143,935 | 88,776 |
| Coal mining | 13,530 | 1,027 | 7,172 | 2,105 |
| Other | 2,032 | 3,250 | 5,042 | 6,200 |
| | **353,196** | **295,328** | **691,458** | **624,807** |
| **Operating margins** | **36,931** | **42,171** | **73,869** | **64,241** |
| **Other income** | | | | |
| Interest | 2,562 | 4,941 | 5,611 | 6,440 |
| Capital credits from cooperatives | 22 | — | 1,135 | 1,281 |
| Other income | 477 | (1,197) | 634 | 4,123 |
| | **3,061** | **3,744** | **7,380** | **11,844** |
| **Interest expense** | | | | |
| Interest | 47,587 | 45,379 | 90,655 | 89,705 |
| Interest charged during construction | (5,330) | (2,765) | (10,452) | (4,597) |
| | **42,257** | **42,614** | **80,203** | **85,108** |
| **Income tax expense** | — | — | — | — |
| **Net margins including noncontrolling interest** | **(2,265)** | **3,301** | **1,046** | **(9,023)** |
| **Net margin attributable to noncontrolling interest** | (49) | (2,793) | (95) | (5,497) |
| **Net margins attributable to the Association** | **$ (2,314)** | **$ 508** | **$ 951** | **$ (14,520)** |

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

**Tri-State Generation and Transmission Association, Inc.**
**Consolidated Statements of Comprehensive Income (Loss)** (Unaudited)
*(dollars in thousands)*

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Net margins including noncontrolling interest** | $ (2,265) | $ 3,301 | $ 1,046 | $ (9,023) |
| **Other comprehensive income:** | | | | |
| Unrealized gain on securities available for sale | 55 | 55 | 120 | 65 |
| Amortization of prior service credit on postretirement benefit obligation included in net margin | — | (127) | — | (536) |
| Amortization of prior service cost on executive benefit restoration obligation included in net margin | 60 | 220 | 121 | 509 |
| **Other comprehensive income** | **115** | **148** | **241** | **38** |
| | | | | |
| **Comprehensive income (loss) including noncontrolling interest** | **(2,150)** | **3,449** | **1,287** | **(8,985)** |
| Net comprehensive income attributable to noncontrolling interest | (49) | (2,793) | (95) | (5,497) |
| **Comprehensive income (loss) attributable to the Association** | **$ (2,199)** | **$ 656** | **$ 1,192** | **$ (14,482)** |

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

**Tri-State Generation and Transmission Association, Inc.**
**Consolidated Statements of Equity** (Unaudited)
*(dollars in thousands)*

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Patronage capital equity at beginning of period** | $ 901,705 | $ 969,553 | $ 912,922 | $ 984,581 |
| Net margins attributable to the Association | (2,314) | 508 | 951 | (14,520) |
| Retirement of patronage capital | (1,020) | (82,200) | (15,502) | (82,200) |
| **Patronage capital equity at end of period** | **898,371** | **887,861** | **898,371** | **887,861** |
| **Accumulated other comprehensive gain (loss) at beginning of period** | 1,091 | (949) | 965 | (839) |
| Unrealized gain on securities available for sale | 55 | 55 | 120 | 65 |
| Reclassification adjustment of prior service credit on postretirement benefit obligation included in net margin | — | (127) | — | (536) |
| Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin | 60 | 220 | 121 | 509 |
| **Accumulated other comprehensive gain (loss) at end of period** | **1,206** | **(801)** | **1,206** | **(801)** |
| **Noncontrolling interest at beginning of period** | 130,281 | 126,945 | 130,498 | 134,269 |
| Net comprehensive income attributable to noncontrolling interest | 49 | 2,793 | 95 | 5,497 |
| Equity distribution to noncontrolling interest | — | — | (263) | (10,028) |
| **Noncontrolling interest at end of period** | **130,330** | **129,738** | **130,330** | **129,738** |
| **Total equity at end of period** | **$ 1,029,907** | **$ 1,016,798** | **$ 1,029,907** | **$ 1,016,798** |

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

**Tri-State Generation and Transmission Association, Inc.**
**Consolidated Statements of Cash Flows** (Unaudited)
*(dollars in thousands)*

| | Six Months Ended June 30, 2025 | 2024 |
|---|---|---|
| **Operating activities** | | |
| Net margins including noncontrolling interest | $ 1,046 | $ (9,023) |
| Adjustments to reconcile net margins to net cash provided by operating activities: | | |
| Depreciation, amortization and depletion | 143,935 | 88,776 |
| Amortization of intangible asset | 7,030 | — |
| Amortization of NRECA Retirement Security Plan prepayment | 2,686 | 2,686 |
| Amortization of debt issuance costs | 1,047 | 1,462 |
| Accretion of asset retirement obligation | 4,263 | 3,962 |
| Deposits associated with generator interconnection requests | (7,047) | 9,932 |
| Rate stabilization revenue | (88,126) | (16,901) |
| Capital credit allocations from cooperatives and income from coal mines under refund distributions | 1,864 | 1,914 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (5,703) | 3,188 |
| Coal inventory | (11,745) | (16,105) |
| Materials and supplies | (5,944) | (3,557) |
| Accounts payable and accrued expenses | (2,776) | (527) |
| Accrued interest | 1,296 | (2,004) |
| Accrued property taxes | (12,898) | (11,548) |
| Deferred membership withdrawal | 86,033 | 709,395 |
| Other | (7,869) | (18,063) |
| **Net cash provided by operating activities** | **107,092** | **743,587** |
| **Investing activities** | | |
| Purchases of plant | (178,660) | (155,210) |
| Sale of electric plant | 5,917 | 75,000 |
| Sale of non-utility assets | — | 3,136 |
| Purchase of investments | — | (95,000) |
| Changes in deferred charges | (9,470) | (5,245) |
| **Net cash used in investing activities** | **(182,213)** | **(177,319)** |
| **Financing activities** | | |
| Changes in Member advances | (104) | (3,677) |
| Payments of long-term debt | (70,665) | (222,881) |
| Proceeds from issuance of long-term debt | 74,000 | — |
| Debt issuance costs | (1,054) | (8) |
| Change in short-term borrowings, net | 44,554 | (68,304) |
| Retirement of patronage capital | (19,234) | (87,414) |
| Equity distribution to noncontrolling interest | (263) | (10,028) |
| Other | (570) | (527) |
| **Net cash provided by financing activities** | **26,664** | **(392,839)** |
| **Net increase in cash, cash equivalents and restricted cash and investments** | **(48,457)** | **173,429** |
| **Cash, cash equivalents and restricted cash and investments – beginning** | **233,537** | **110,018** |
| **Cash, cash equivalents and restricted cash and investments – ending** | **$ 185,080** | **$ 283,447** |
| **Supplemental cash flow information:** | | |
| Cash paid for interest | $ 73,721 | $ 86,937 |
| Cash paid for income taxes | $ — | $ — |
| **Supplemental disclosure of noncash investing and financing activities:** | | |
| Change in plant expenditures included in accounts payable | $ 4,484 | $ (2,769) |
| Lease asset additions | $ 927 | $ 4,509 |

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

# Tri-State Generation and Transmission Association, Inc.
# Notes to Unaudited Consolidated Financial Statements
# For the Three and Six Months Ended June 30, 2025 and 2024

## NOTE 1 – PRESENTATION OF FINANCIAL INFORMATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. These unaudited consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2024 filed with the SEC. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. Our consolidated financial position as of June 30, 2025, results of operations for the three and six months ended June 30, 2025 and 2024, and cash flows for the six months ended June 30, 2025 and 2024 are not necessarily indicative of the results that may be expected for an entire year or any other period.

*Basis of Consolidation*

We are a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis serving large portions of Colorado, Nebraska, New Mexico and Wyoming. We were incorporated under the laws of the State of Colorado in 1952. We have forty electric distribution member systems ("Utility Members") who are Class A - utility full requirements members to which we provided electric power pursuant to long-term wholesale electric service contracts. We have three non-utility members ("Non-Utility Members"). Our Class A Utility Members and Non-Utility Members are collectively referred to as our "Members." Our rates to our Utility Members are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). On July 30, 2024, FERC issued an order accepting our A-41 formula rate to our Utility Members, effective August 1, 2024, subject to refund. FERC further set our A-41 rate filing for settlement and hearing procedures.

On February 1, 2025, Mountain Park Electric, Inc. ("MPEI") withdrew from membership in us and pursuant to Rate Schedule 281 (contract termination payment methodology) on-file with FERC and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. MPEI's contract termination payment amount was $86.0 million, including MPEI's pro rata share of our power purchase obligations in the Western Interconnection. MPEI paid us an exit fee in cash of $71.6 million and relinquished its right to any patronage capital in us resulting in a discounted patronage capital credit of $14.5 million. In May 2025, we trued-up MPEI's discounted patronage capital in accordance with Rate Schedule 281 and MPEI's Membership Withdrawal Agreement resulting in a payment to MPEI of $1 million that was made in June 2025. Our Board deferred a portion of the contract termination payment and a portion was related to a transmission credit that was deferred as required by FERC's orders on our Rate Schedule 281. The portion of the contract termination payment allocated to the transmission credit for both United Power and MPEI is subject to further change based upon FERC's August 2025 order of our February 2025 and May 2025 compliance filings related to Rate Schedule 281.

We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with GAAP, the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

The accompanying financial statements reflect the consolidated accounts of Tri-State Generation and Transmission Association, Inc. ("Tri-State", "we", "our", "us" or "the Association"), our wholly-owned and majority-owned subsidiaries, and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 17 – Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities. We have eliminated all intercompany balances and transactions in consolidation.

*Accounting Pronouncement - Not Yet Adopted*

In November 2024, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2024-03, Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures. ASU 2024-03 requires a public business entity to disclose in a tabular format, on an annual and interim basis, purchases of inventory, employee compensation, depreciation, intangible asset amortization and depletion for each income statement line item that contains those expenses in the notes to the financial statements. Specified expenses, gains and losses that are already disclosed under existing GAAP are also required to be included in the disaggregated income statement expense line item disclosures and any remaining amounts need to be described qualitatively. Separate disclosures of total selling expenses and an entity's definition of those expenses are also required. ASU 2024-03 is effective for fiscal years beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted. Entities may apply the guidance prospectively or retrospectively.

In December 2023, FASB issued ASU 2023-09 – Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The purpose of ASU 2023-09 is to enhance the transparency and decision usefulness of income tax disclosures by providing additional information related to the following:

(1) Rate reconciliation: ASU 2023-09 requires a tabular rate reconciliation using both percentages and dollar amounts of the reported income tax expense (or benefit) from continuing operations to the product of income (or loss) from continuing operating before income taxes and the applicable statutory federal income tax rate of the county of domicile using specific categories. The following specific categories are required to be disclosed in the rate reconciliation; state and local income tax (qualitative disclosure required for states that make up over 50% of this category), foreign tax effect, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items, changes in unrecognized tax benefits, and any other item that meets the 5 percent threshold.

(2) Income taxes paid: ASU 2023-09 requires all reporting entities to disclose the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign jurisdictions. It also requires additional disaggregation of income taxes paid to an individual jurisdiction equal to or greater than 5 percent of total income taxes paid (net of refunds). Entities are required to disclose pre-tax income (or loss) from continuing operations disaggregated by domestic and foreign along with income tax expense (or benefit) disaggregated by federal, state, and foreign components.

ASU 2023-09 is effective for public business entities for annual periods beginning after December 15, 2024, with early adoption and retrospective or prospective application permitted. We have evaluated the impact of ASU 2023-09 and believe that the adoption of this update will not have a material impact on our consolidated financial statement disclosures.

## NOTE 2 – ACCOUNTING FOR RATE REGULATION

In accordance with the accounting requirements related to regulated operations, some revenues and expenses have been deferred at the discretion of our Board, subject to FERC approval, if based on regulatory orders or other available evidence, it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs that we expect to recover from our Utility Members based on rates approved by the applicable authority. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Utility Members based on rates approved by the applicable authority. Amounts that are no longer expected to be refunded to our Utility Members are recognized in margins. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expense concurrent with their recovery through rates. As a cooperative, we don't earn a rate of return on regulatory items.

Regulatory assets and liabilities are as follows (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| **Regulatory assets** | | |
| Deferred income tax expense (1) | $ 12,217 | $ 12,217 |
| Deferred prepaid lease expense – Springerville Unit 3 Lease (2) | 71,115 | 72,260 |
| Deferred debt prepayment transaction costs (3) | 93,474 | 97,789 |
| Deferred Holcomb expansion impairment loss (4) | 67,783 | 70,121 |
| New Horizon Mine environmental obligation (5) | 43,224 | 44,121 |
| Unrecovered plant (6) | 513,642 | 520,033 |
| **Total regulatory assets** | **801,455** | **816,541** |
| | | |
| **Regulatory liabilities** | | |
| Interest rate swap - realized gain (7) | 1,154 | 1,390 |
| Membership withdrawal (8) | 239,691 | 319,368 |
| Withdrawal related transmission credit (9) | 249,827 | 176,270 |
| **Total regulatory liabilities** | **490,672** | **497,028** |
| **Net regulatory asset** | **$ 310,783** | **$ 319,513** |

(1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.

(2) Represents deferral of the loss on acquisition related to the Springerville Generating Station Unit 3 (“Springerville Unit 3”) prepaid lease expense upon acquiring a controlling interest in the Springerville Unit 3 Partnership LP (“Springerville Partnership”) in 2009. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Utility Members through rates.

(3) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of $8.6 million annually over the 21.4-year period ending in 2036 and recovered from our Utility Members through rates.

(4) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights for the expansion of the Holcomb Generating Station. The regulatory asset for the deferred impairment loss is being amortized to depreciation, amortization and depletion expense in the amount of $4.7 million annually over the 20-year period ending in 2039 and recovered from our Utility Members through rates.

(5) Represents $44.9 million of New Horizon Mine environmental obligation expense that was recognized as a regulatory item in 2023. The regulatory asset for the deferred environmental obligation expense is being amortized to depreciation, amortization and depletion expense in the amount of $1.8 million annually over 25 years ending in 2049 and recovered from our Utility Members through rates.

(6) Represents deferral of the impairment losses and other closure costs related to the early retirement of the Escalante, Rifle and Craig Generating Station Units 2 and 3. The deferred impairment loss for Escalante Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $12.2 million annually over the 25-year period ending in December 2045, which was the depreciable life of the Escalante Generating Station, and recovered from our Utility Members through rates. The deferred impairment loss for Rifle Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $0.6 million annually through December 2028, which was the depreciable life of the Rifle Generating Station, and recovered from our Utility Members in rates. We recognized the early retirement of Craig Generating Station Units 2 and 3. We recognized an impairment loss of $261.6 million and deferred the loss in accordance with accounting for rate regulation. The deferred impairment loss will be amortized to depreciation, amortization and depletion expense beginning in October 2028 through 2039 for Craig Generating Station Unit 2 and January 2030 through 2043 for Craig Generating Station Unit 3 and will be recovered from our Utility Members through future rates. These amortization periods are the depreciable lives of Craig Generating Station Unit 2 and 3. The annual amortization is expected to approximate the former annual Craig Generation Station Unit 2 and 3 depreciation for the remaining life of the asset.

(7) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12–year term of the First Mortgage Obligations, Series 2017A and refunded to Utility Members through reduced rates when recognized in future periods.

(8) Represents the remaining balance of the deferred recognition of other operating revenues related to the withdrawal of former Utility Members from membership in us. On February 1, 2025, MPEI withdrew from membership in us and MPEI's contract termination payment amount was $86.0 million, of which $60.6 million we estimate, based upon FERC's April 2025 order on our Rate Schedule 281, was membership withdrawal that was deferred by our Board as a regulatory liability. Based on FERC's April 2025 FERC order on our Rate Schedule 281, we adjusted the United Power Inc. ("United Power") deferred membership withdrawal income from $530.1 million to $478.0 million and the United Power transmission credit from $179.3 million to $231.4 million. The MPEI deferred membership withdrawal income and transmission credit are based upon such April 2025 FERC order. The deferred membership withdrawal will be refunded to Utility Members through reduced rates when recognized in operating revenues in future periods with the oldest vintage year used first. During the six months ended June 30, 2025, $88.1 million was recognized in operating revenues as part of our rate stabilization measures. See Note 13 - Revenue and Note 18 - Legal.

(9) Represents the remaining amount of the United Power and MPEI transmission credits related to taking transmission service from us. A portion of a withdrawing member's contract termination payment is allocated to transmission debt that is deferred as required by FERC's orders on Rate Schedule 281. The transmission credit, plus interest at FERC's prescribed interest rate, is refunded to the former Utility Member on a monthly basis if the former Utility Member takes transmission service from us and amortized on a straight-line basis over the remaining term. If the former Utility Member's transmission bill for a given month is lower than the credit amount that would be due, the difference is forfeited by the former Utility Member.

**NOTE 3 – PROPERTY, PLANT AND EQUIPMENT**

Our property, plant and equipment consists of electric plant and other plant. Both of these are discussed below and are included on our consolidated statements of financial position.

**ELECTRIC PLANT**: As of June 30, 2025, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

| | Annual Depreciation Rate | | | Plant In Service | Accumulated Depreciation | Net Book Value |
|---|---|---|---|---|---|---|
| Generation plant | 1.14 % | to | 4.14 % | $ 3,105,374 | $ (1,786,720) | $ 1,318,654 |
| Transmission plant | 1.17 % | to | 1.84 % | 2,028,693 | (725,061) | 1,303,632 |
| General plant | 1.20 % | to | 11.60 % | 439,159 | (289,667) | 149,492 |
| Other | 2.75 % | to | 10.00 % | 239,861 | (100,272) | 139,589 |
| **Electric plant in service (at cost)** | | | | **$ 5,813,087** | **$ (2,901,720)** | **2,911,367** |
| Construction work in progress | | | | | | 424,029 |
| **Electric plant** | | | | | | **$ 3,335,396** |

As of December 31, 2024, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

| | Annual Depreciation Rate | | | Plant In Service | Accumulated Depreciation | Net Book Value |
|---|---|---|---|---|---|---|
| Generation plant | 1.14 % | to | 4.14 % | $ 3,100,656 | $ (1,744,837) | $ 1,355,819 |
| Transmission plant | 1.17 % | to | 1.84 % | 1,933,206 | (715,505) | 1,217,701 |
| General plant | 1.20 % | to | 11.60 % | 426,615 | (279,678) | 146,937 |
| Other | 2.75 % | to | 10.00 % | 240,705 | (98,857) | 141,848 |
| **Electric plant in service (at cost)** | | | | **$ 5,701,182** | **$ (2,838,877)** | **2,862,305** |
| Construction work in progress | | | | | | 368,473 |
| **Electric plant** | | | | | | **$ 3,230,778** |

In 2024, we purchased both the 145 MW Axial Basin Solar project being developed in northwestern Colorado and the 110 MW Dolores Canyon Solar project being developed in southwestern Colorado. Both projects are under construction and are expected to achieve commercial operation in the fourth quarter of 2025.

Both acquisitions were accounted for as an asset acquisition in accordance with the accounting requirements for business combinations since we purchased the project assets and not a business. As such, the asset acquisitions and subsequent facility development costs are being capitalized which is included in construction work in progress.

**JOINTLY OWNED FACILITIES**: Our share in each jointly owned facility is as follows as of June 30, 2025 (these electric plant in service, accumulated depreciation and construction work in progress amounts are included in the electric plant table above) (dollars in thousands):

| | Tri-State Share | Electric Plant in Service | Accumulated Depreciation | Construction Work In Progress |
|---|---|---|---|---|
| Yampa Project - Craig Generating Station Units 1 and 2 | 24.00 % | $ 392,510 | $ 282,624 | $ — |
| MBPP - Laramie River Station | 28.50 % | 540,952 | 356,174 | 1,762 |
| **Total** | | **$ 933,462** | **$ 638,798** | **$ 1,762** |

**OTHER PLANT**: Other plant consists of mine assets (discussed below) and non-utility assets which consist of facilities not in service, land and irrigation equipment.

We own 100 percent of Elk Ridge Mining and Reclamation, LLC (“Elk Ridge”), organized for the purpose of acquiring coal reserves and supplying coal to us. Elk Ridge is the owner of the Colowyo Mine, a surface coal mine near Craig, Colorado, and the New Horizon Mine near Nucla, Colorado. The New Horizon Mine is in post-reclamation monitoring and no longer produces coal. The expenses related to the Colowyo Mine coal used by us are included in fuel expense on our consolidated statements of operations.

Other plant assets are as follows (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Colowyo Mine assets | $ 402,927 | $ 403,482 |
| New Horizon Mine assets | 6,287 | 6,287 |
| Accumulated depreciation and depletion | (295,128) | (242,654) |
| **Net mine assets** | **114,086** | **167,115** |
| Non-utility assets | 549,224 | 549,224 |
| Accumulated depreciation | (527,628) | (527,616) |
| **Net non-utility assets** | **21,596** | **21,608** |
| **Net other plant** | **$ 135,682** | **$ 188,723** |

**NOTE 4 – INVESTMENTS IN OTHER ASSOCIATIONS**

Investments in other associations include investments in the patronage capital of other cooperatives and other required investments in the organizations. Our investment in a cooperative increases when a cooperative allocates patronage capital credits to us and it decreases when we receive a cash retirement of the allocated capital credits from the cooperative. A cooperative allocates its patronage capital credits to us based upon our patronage (amount of business done) with the cooperative.

Investments in other associations are as follows (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Basin Electric Power Cooperative | $ 139,793 | $ 140,025 |
| National Rural Utilities Cooperative Finance Corporation - patronage capital | 12,599 | 12,599 |
| National Rural Utilities Cooperative Finance Corporation - capital term certificates | 15,054 | 15,054 |
| CoBank, ACB | 17,960 | 19,500 |
| Other | 5,396 | 5,502 |
| **Investments in other associations** | **$ 190,802** | **$ 192,680** |

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during the six months ended June 30, 2025 or during 2024.

**NOTE 5 – CASH, CASH EQUIVALENTS AND RESTRICTED CASH AND INVESTMENTS**

We consider highly liquid investments with an original maturity of three months or less to be cash equivalents. The fair value of cash equivalents approximates their carrying values due to their short-term maturity.

Restricted cash and investments represent funds designated by our Board for specific uses and funds restricted by contract or other legal reasons. A portion of the funds are amounts that have been restricted by contract that are expected to be settled within one year. These funds are therefore classified as current on our consolidated statements of financial position. The other funds are for amounts restricted by contract or other legal reasons that are expected to be settled beyond one year. These funds are classified as noncurrent and are included in other assets and investments on our consolidated statements of financial position.

The following table provides a reconciliation of cash, cash equivalents and restricted cash and investments reported within our consolidated statements of financial position that sum to the total of the same such amount shown in our consolidated statements of cash flows (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Cash and cash equivalents | $ 181,507 | $ 229,357 |
| Restricted cash and investments - current | 1,266 | 744 |
| Restricted cash and investments - noncurrent | 2,307 | 3,436 |
| **Cash, cash equivalents and restricted cash and investments** | **$ 185,080** | **$ 233,537** |

**NOTE 6 – CONTRACT ASSETS AND CONTRACT LIABILITIES**

*Accounts Receivable*

We record accounts receivable for our unconditional rights to consideration arising from our performance under contracts with our Members and other parties. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible. See Note 13 – Revenue.

*Contract liabilities (unearned revenue)*

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. During the six months ended June 30, 2025, we recognized $0.3 million of this unearned revenue in other operating revenues on our consolidated statements of operations.

Our contract assets and liabilities consist of the following (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| **Accounts receivable - Utility Members** | **$ 95,565** | **$ 85,450** |
| | | |
| **Other accounts receivable - trade:** | | |
| Non-member electric sales | 11,835 | 21,035 |
| Other | 8,970 | 3,642 |
| **Total other accounts receivable - trade** | **20,805** | **24,677** |
| Other accounts receivable - nontrade | 3,512 | 4,050 |
| **Total other accounts receivable** | **$ 24,317** | **$ 28,727** |
| | | |
| **Contract liabilities (unearned revenue)** | **$ 3,194** | **$ 3,480** |

**NOTE 7 – OTHER DEFERRED CHARGES**

The following other deferred charges are reflected on our consolidated statements of financial position (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Preliminary surveys and investigations | $ 12,525 | $ 12,192 |
| Advances to operating agents of jointly owned facilities | 16,972 | 7,502 |
| Lease right-of-use assets | 10,583 | 10,177 |
| Other | 20,619 | 21,864 |
| **Total other deferred charges** | **$ 60,699** | **$ 51,735** |

We make expenditures for preliminary surveys and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects. If construction results, the preliminary survey and investigation expenditures will be reclassified to electric plant - construction work in progress. If the work is abandoned, the related preliminary survey and investigation expenditures will be charged to the appropriate operating expense account or the expense could be deferred as a regulatory asset to be recovered from our Utility Members through rates subject to approval by our Board and FERC.

We make advance payments to the operating agents of jointly owned facilities to fund our share of costs expected to be incurred under each project including MBPP – Laramie River Station, and Yampa Project – Craig Generating Station Units 1 and 2. We also make advance payments to the operating agent of Springerville Unit 3.

A right-of-use asset represents a lessee's right to control the use of the underlying asset for the lease term. Right-of-use assets are included in other deferred charges and presented net of accumulated amortization. See Note 15 – Leases.

**NOTE 8 – LONG-TERM DEBT**

We have $2.9 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture"). Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a debt service ratio ("DSR") requirement on an annual basis and an equity to capitalization ratio ("ECR") requirement of at least 18 percent at the end of each fiscal year. Other than long-term debt for the Springerville certificates that has a DSR requirement of at least 1.02 on an annual basis, all other long-term debt contains a DSR requirement of at least 1.10 on an annual basis. A DSR below 1.025 under the Master Indenture would require us to transfer all cash to a special fund managed by the trustee of the Master Indenture.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC"), as lead arranger and administrative agent, in the amount of $520 million ("2022 Revolving Credit Agreement") that expires on April 25, 2027 and includes a swingline sublimit of $125 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million. As of June 30, 2025, we had $472 million in availability (including $72 million under the letter of credit sublimit and $455 million under the commercial paper back-up sublimit) under the 2022 Revolving Credit Agreement.

On June 18, 2025, we entered into a renewable secured revolving credit facility with CoBank, as lead arranger, and CFC, as administrative agent, in the amount of $250 million ("Renewable Revolving Credit Agreement") that expires on June 18, 2030. The proceeds from this facility are required to be used for eligible green investments, as defined in the Renewable Revolving Credit Agreement. As of June 30, 2025, we had borrowed $74 million in adjusted Term SOFR rate loans and $176 million of availability remained.

Long-term debt consists of the following (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Total debt | $ 2,965,228 | $ 2,961,992 |
| Less debt issuance costs | (17,697) | (17,690) |
| Less debt discounts | (8,228) | (8,380) |
| Plus debt premiums | 9,664 | 10,082 |
| **Total debt adjusted for debt issuance costs, discounts and premiums** | **2,948,967** | **2,946,004** |
| Less current maturities | (78,944) | (88,658) |
| **Long-term debt** | **$ 2,870,023** | **$ 2,857,346** |

As a requirement of a loan from the Rural Utilities Services ("RUS") provided as part of the Rural Energy Savings Program and our Electrify and Save® On-Bill Repayment Program, we are required to maintain a letter of credit for the benefit of RUS, which is currently in the amount of $3 million.

**NOTE 9 – SHORT-TERM BORROWINGS**

We have a commercial paper program under which we issue unsecured commercial paper in aggregate amounts not exceeding the commercial paper back-up sublimit under our 2022 Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our 2022 Revolving Credit Agreement. The commercial paper issuances are used to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances vary but may not exceed 397 days from the date of issue. The commercial paper notes are classified as current and are included in current liabilities as short-term borrowings on our consolidated statements of financial position.

Short-term borrowings consisted of the following (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Commercial paper outstanding, net of discounts | $ 44,654 | $ — |
| Short-term borrowings - other | $ 100 | $ 100 |
| Weighted average interest rate | 4.65 % | — % |

As of June 30, 2025, we had $45 million commercial paper outstanding and $455 million of the commercial paper back-up sublimit remained available under the 2022 Revolving Credit Agreement. See Note 8 – Long-Term Debt.

**NOTE 10 – ASSET RETIREMENT AND ENVIRONMENTAL REMEDIATION OBLIGATIONS**

We account for current obligations associated with the future retirement of tangible long-lived assets and environmental remediation in accordance with the accounting guidance relating to asset retirement and environmental obligations. This guidance requires that legal obligations associated with the retirement of long-lived assets be recognized at fair value at the time the liability is incurred and capitalized as part of the related long-lived asset. Over time, the liability is adjusted to its present value by recognizing accretion expense and the capitalized cost of the long-lived asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. In the absence of quoted market prices, we determine fair value by using present value techniques in which estimates of future cash flows associated with retirement activities are discounted using a credit adjusted risk-free rate and market risk premium. Upon settlement of an asset retirement obligation, we will apply payment against the estimated liability and incur a gain or loss if the actual retirement costs differ from the estimated recorded liability.

Environmental remediation costs are accrued based on management's best estimate at the end of each period of the costs expected to be incurred. Such cost estimates may include ongoing care, maintenance and monitoring costs. Changes in reclamation estimates are reflected in earnings in the period an estimate is revised.

Coal mines: We have asset retirement obligations for the final reclamation costs and environmental obligations for post-reclamation monitoring related to the Colowyo Mine and the New Horizon Mine. The New Horizon Mine is currently in post-reclamation monitoring. Two pits at the Colowyo Mine are in final reclamation with the other pit still being actively mined.

Generation: We have asset retirement obligations related to equipment, dams, ponds, wells and underground storage tanks at the generating stations.

Aggregate carrying amounts of asset retirement obligations and environmental remediation obligations are as follows (dollars in thousands):

| | Six Months Ended June 30, 2025 |
|---|---|
| Obligations at beginning of period | $ 271,891 |
| Liabilities incurred | 3,518 |
| Liabilities settled | (6,932) |
| Accretion expense | 3,894 |
| **Total obligations at end of period** | **$ 272,371** |
| Less current obligations at end of period | (72,670) |
| **Long-term obligations at end of period** | **$ 199,701** |

The New Horizon Mine environmental remediation liability balance is $68.5 million as of June 30, 2025. Of this amount, $24.7 million is recorded on a discounted basis, using a discount rate of 6.73 percent, with total estimated undiscounted future cash outflows of $36.6 million. Environmental obligation expense is included in other operating expenses on our consolidated statements of operations. During the first quarter of 2025, we recognized a change in estimate related to the Colowyo Mine asset retirement obligation due to a change in the planned timing of full reclamation to 2025 and an updated cost estimate. We continue to evaluate the New Horizon Mine and Colowyo Mine post reclamation obligations and will make adjustments to these obligations as needed.

We also have asset retirement obligations with indeterminate settlement dates. These are made up primarily of obligations attached to transmission and other easements that are considered by us to be operated in perpetuity and therefore the measurement of the obligation is not possible. A liability will be recognized in the period in which sufficient information exists to estimate a range of potential settlement dates as is needed to employ a present value technique to estimate fair value. During the first quarter of 2025, we recognized a liability totaling $3.5 million related to transmission assets that will be settled between 2026 and 2028.

In May 2024, the Environmental Protection Agency ("EPA") published a final rule regarding groundwater monitoring, corrective action, closure, and post-closure care requirements for all coal combustion residuals management units under the Resource Conservation and Recovery Act. We are analyzing the final rule for possible impacts on our operations.

**NOTE 11 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES**

The following other deferred credits and other liabilities are reflected on our consolidated statements of financial position (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Transmission easements | $ 15,659 | $ 18,517 |
| OATT deposits | 25,367 | 32,587 |
| Financial liabilities - reclamation | 9,397 | 11,077 |
| Customer deposits | 15,454 | 14,955 |
| Contract liabilities (unearned revenue) - noncurrent | 3,194 | 3,480 |
| Lease liabilities - noncurrent | 6,015 | 5,715 |
| Other | 6,670 | 6,727 |
| **Total other deferred credits and other liabilities** | **$ 81,756** | **$ 93,058** |

In 2015, we renewed transmission right-of-way easements on tribal nation lands where certain of our electric transmission lines are located. $22.4 million will be paid by us for these easements from 2025 through the individual easement terms ending between 2035 and 2047 (prior to the easement termination event described below). The present values for the remaining easement payments were $15.7 million as of June 30, 2025 and $18.5 million as of December 31, 2024, respectively, which are recorded as other deferred credits and other liabilities. In April 2025, we submitted a notice of our intent to early terminate a portion of one of our easements on tribal nation lands related to decommissioning of a segment of the transmission line located on that right-of-way, which is anticipated to be undertaken during the spring through fall of 2026. We recognized a $1.0 million fee associated with the early termination in transmission expense on our consolidated statements of operations during the second quarter of 2025.

OATT deposits represent refundable transmission customer deposits related to interconnection and transmission requests from third parties. An OATT deposit is refundable as provided in our Open Access Transmission Tariff.

Financial liabilities - reclamation represent financial obligations that we have for our share of reclamation costs at jointly owned facilities in which we have undivided interests in.

A lease liability represents a lessee's obligation to make lease payments over the lease term. The long-term portion of our lease liabilities are included in other deferred credits and other liabilities and the current portion of our lease liabilities are included in current liabilities. See Note 15 – Leases.

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in contract liabilities (unearned revenue) until recognized in other operating revenues over the life of the agreement. We have received deposits from various parties and those that may still be required to be returned are a liability and these are reflected in customer deposits.

**NOTE 12 – EMPLOYEE BENEFIT PLANS**

*Postretirement Benefits Other Than Pensions*

We sponsor three medical plans for all non-bargaining unit employees under the age of 65. Two of the plans provide postretirement medical benefits to full-time non-bargaining unit employees and retirees who receive benefits under those plans, who have attained age 55, and who elect to participate. All three of these non-bargaining unit medical plans offer post employment medical benefits to employees on long-term disability. The plans were unfunded as of June 30, 2025, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles. As of June 30, 2021, the plans ceased to provide postretirement medical benefits for employees who retire after June 30, 2021.

The postretirement medical benefit and post employment medical benefit obligations are determined annually (during the fourth quarter) by an independent actuary and are included in accumulated postretirement benefit and post employment obligations on our consolidated statements of financial position as follows (dollars in thousands):

| | | Six Months Ended June 30, 2025 |
|---|---|---|
| Postretirement medical benefit obligation at beginning of period | $ | 509 |
| Interest cost | | 16 |
| Benefit payments (net of contributions by participants) | | (158) |
| **Postretirement medical benefit obligation at end of period** | **$** | **367** |
| Postemployment medical benefit obligation at end of period | | 175 |
| **Total postretirement and postemployment medical obligations at end of period** | **$** | **542** |

The service cost component of our net periodic benefit cost, if any, is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations.

In accordance with the accounting standard related to postretirement benefits other than pensions, actuarial gains and losses are not recognized in income but are instead recorded in accumulated other income on our consolidated statements of financial position. If the unrecognized amount is in excess of 10 percent of the projected benefit obligation, amounts are reclassified out of accumulated other comprehensive income and included in net income as the excess is amortized over the average remaining service lives of the active plan participants. Unrecognized actuarial gains and losses have been determined per actuarial studies for the postretirement medical benefit obligation.

The net unrecognized actuarial gains and losses related to the postretirement medical benefit obligations are included in accumulated other comprehensive income as follows (dollars in thousands):

| | | Six Months Ended June 30, 2025 |
|---|---|---|
| Amounts included in accumulated other comprehensive income at beginning of period | $ | 310 |
| Amortization of prior service credit into other income | | — |
| **Amounts included in accumulated other comprehensive income at end of period** | **$** | **310** |

*Defined Benefit Plans*

We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan, both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees with a hire date prior to May 1, 2021 participate in one of the following pension restoration plans: the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan. Eligibility is determined annually and is based on January 1 base salary that exceeds the limits of the defined benefit plan. Employees hired May 1, 2021 or later are not eligible for either plan.

The NRECA Executive Benefit Restoration Plan obligations are determined annually (during the first quarter of the subsequent year) by an NRECA actuary and are included in accumulated postretirement benefit and post employment obligations on our consolidated statements of financial position as follows (dollars in thousands):

| | Six Months Ended June 30, 2025 |
|---|---|
| Executive benefit restoration obligation at beginning of period | $ 7,918 |
| Service cost | 222 |
| Interest cost | 260 |
| **Executive benefit restoration at end of period** | **$ 8,400** |
| Fair value of plan assets at beginning of period | $ 9,829 |
| Actual return on plan assets | 304 |
| **Fair value of plan assets at end of period** | **$ 10,133** |
| **Net liability at end of period** | **$ 1,733** |

The service cost component of our net periodic benefit cost is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations. We have an irrevocable trust with an independent third party to fund the NRECA Executive Benefit Restoration Plan. The trust is funded quarterly to the prior year obligation as determined by the NRECA actuary.

In accordance with the accounting standard related to defined benefit pension plans, actuarial gains and losses are not recognized in income but are instead recorded in accumulated other income on our consolidated statements of financial position. If the unrecognized amount is in excess of 10 percent of the projected benefit obligation, amounts are reclassified out of accumulated other comprehensive income and included in net income as the excess is amortized over the average remaining service lives of the active plan participants. Unrecognized actuarial gains and losses have been determined per actuarial studies for the executive benefit restoration obligation.

The net unrecognized actuarial gains and losses related to the executive benefit restoration obligations are included in accumulated other comprehensive income as follows (dollars in thousands):

| | Six Months Ended June 30, 2025 |
|---|---|
| Accumulated other comprehensive loss at beginning of period | $ 814 |
| Amortization of prior service cost into other income | 121 |
| **Accumulated other comprehensive loss at end of period** | **$ 935** |

## NOTE 13 – REVENUE

*Revenue from Contracts with Customers*

Our revenues are derived primarily from the sale of wholesale electric service to our Utility Members pursuant to long-term wholesale electric service contracts. In June 2025, we and a majority of our Utility Members separately entered into revised wholesale electric service contracts that were filed with FERC. In August 2025, FERC accepted such revised wholesale electric service contracts, with a August 6, 2025 effective date, subject to refund. FERC further set our revised wholesale electric service contracts for settlement and hearing procedures. The revised wholesale electric service contracts supersede the Utility Member's respective 2007 wholesale electric service contract, which extended through 2050. Thirty-two of our Utility Members' revised wholesale electric service contracts have an initial expiration date of December 31, 2066. Four of our Utility Members' revised wholesale electric service contracts continue to have an initial expiration date of December 31, 2050. Four of our Utility Members elected not to sign the revised wholesale electric service contract, and such Utility Members' 2007 wholesale electric service contracts have an initial expiration date of December 31, 2050.

*Member electric sales*

Revenues from wholesale electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule filed with FERC. Our Class A rate schedule (A-40) was a stated rate and accepted by FERC on March 20, 2020. Our

A-40 rate for electric power sales to our Utility Members remained in effect until July 31, 2024 and consisted of three billing components: an energy rate and two demand rates.

Our Class A rate schedule (A-41) for electric power sales to our Utility Members was accepted by FERC, effective August 1, 2024, subject to refund, and incorporated a new formulary rate, which can be adjusted annually based on the budgets approved by our Board, including an annual true-up mechanism. Our A-41 rate consists of eleven rate components, with three energy based and eight demand based. Our budget used to set our Utility Members' formula rate is set by our Board.

Energy and demand have the same pattern of transfer to our Utility Members and are both measurements of the electric power provided to our Utility Members. Therefore, the provision of electric power to our Utility Members is one performance obligation. Prior to our Utility Members' requirement for electric power, we do not have a contractual right to consideration as we are not obligated to provide electric power until the Utility Member requires each incremental unit of electric power. We transfer control of the electric power to our Utility Members over time and our Utility Members simultaneously receive and consume the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method, meter readings are taken at the end of each month for billing purposes, energy and demand are determined after the meter readings and Utility Members are invoiced based on the meter reading. Payments from our Utility Members are received in accordance with the wholesale electric service contracts' terms, which is less than 30 days from the invoice date. Utility Member electric sales revenue is recorded as Utility Member electric sales on our consolidated statements of operations and Accounts receivable – Utility Members on our consolidated statements of financial position.

Revenue from one Utility Member, Poudre Valley Rural Electric Association, was $62.4 million, or 12.2 percent, of our Utility Member revenue and 8.2 percent of our total operating revenues six months ended June 30, 2025. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues during the six months ended June 30, 2025.

In addition to our Utility Member electric sales, we have non-member electric sales and other operating revenue which consist of several revenue streams. The following revenue is reflected on our consolidated statements of operations as follows (dollars in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Non-member electric sales:** | | | | |
| Long-term contracts | $ 36,479 | $ 29,813 | $ 75,273 | $ 51,188 |
| Short-term contracts | 8,018 | 8,955 | 17,630 | 23,199 |
| Rate stabilization | 43,183 | 16,901 | 88,126 | 16,901 |
| Provision for rate refunds | 5,273 | — | 2,719 | — |
| Coal sales | 12,466 | 1,814 | 12,466 | 3,458 |
| Other | 27,059 | 21,730 | 55,464 | 40,190 |
| **Total non-member electric sales and other operating revenue** | **$ 132,478** | **$ 79,213** | **$ 251,678** | **$ 134,936** |

*Non-member electric sales*

Revenues from wholesale electric power sales to non-members are primarily from long-term contracts and short-term market sales. Prior to our customers' demand for energy, we do not have a contractual right to consideration as we are not obligated to provide energy until the customer demands each incremental unit of energy. We transfer control of the energy to our customer over time and our customer simultaneously receives and consumes the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method. Payments are received in accordance with the contract terms, which is less than 30 days after the invoice is received by the customer.

Revenue from three non-members, United Power, Salt River Project Agricultural Improvement and Power District, and Western Area Power Administration, was $24.2 million, $18.6 million and $16.2 million, respectively, or 26.1 percent, 20.0 percent and 17.5 percent, respectively, of non-member electric sales and 3.2 percent, 2.4 percent and 2.1 percent, respectively, of our total operating revenues for the six months ended June 30, 2025. No other non-member exceeded 10 percent of our total non-member electric sales or our total operating revenues for the six months ended June 30, 2025.

*Provision for Rate Refunds*

In December 2024, we recorded a provision for rate refund in the amount of $2.5 million and in March 2025, we recorded an additional provision for rate refund in the amount of $2.6 million related to FERC's orders on our Rate Schedule 281 (contract termination payment methodology) that addressed the calculation of a transmission credit for withdrawing Utility Members in the Western Interconnection. Such refund amounts were paid in June 2025 to the two withdrawn Utility Members. See Note 18 - Legal - CTP Proceeding.

*Rate Stabilization*

Rate stabilization represents revenue recognition from withdrawal of former Utility Members from membership in us that was previously deferred in accordance with accounting requirements related to regulated operations. We recognized $88.1 million of deferred membership withdrawal income for the six months ended June 30, 2025 compared to $16.9 million of deferred membership withdrawal income being recognized for the six months ended June 30, 2024. The 2025 deferred membership withdrawal income includes $40.6 million of deferred membership withdrawal income to offset the expense recognition for accelerated expenses related to the transition from mining to full reclamation at the Colowyo Mine in 2025 and $47.5 million in deferred membership withdrawal income related to rate stabilization measures in order to meet our financial ratios and goals.

*Coal sales*

Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. We have an obligation to deliver coal and progress of completion toward our performance obligation is measured using the output method. Our performance obligation is completed as coal is delivered.

*Other operating revenue*

Other operating revenue consists primarily of wheeling, transmission and lease revenue. Other operating revenue also includes revenue we receive from our Non-Utility Members. Wheeling revenue is earned when we charge other energy companies for transmitting electricity over our transmission lines (payments are received in accordance with the contract terms which is within 20 days of the date the invoice is received). Transmission revenue is from Southwest Power Pool’s scheduling of transmission across our transmission assets in the Eastern Interconnection because of our membership in it (Southwest Power Pool collects the revenue from the customer and pays us for the scheduling, system control, dispatch transmission service, and the annual transmission revenue requirement). Each of these services or goods are provided over time and progress toward completion of our performance obligations are measured using the output method. Lease revenue is from lease agreements where we are the lessor for certain operational assets with third parties including a tolling agreements with third parties at our Knutson Generating Station and Pyramid Generating Station. See Note 15 - Leases.

**NOTE 14 – INCOME TAXES**

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. We and our subsidiaries use the flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board and FERC. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Under this regulatory accounting approach, any income tax expense or benefit on our consolidated statements of operation includes only the current portion.

Under ASC 740-270, we calculate an estimate of the provision for income taxes during interim reporting periods by applying an estimate of the annual effective tax rate for the full fiscal year to income or loss (pretax income or loss excluding unusual or infrequently occurring discrete items) for the reporting period, after regulatory affect. Our consolidated statements of operations included no income tax expense or benefit for the six months ended June 30, 2025 and the comparable period in 2024. We are continuing to evaluate the tax impacts of the contract termination payment received from MPEI. Any current tax expense expected to be realized as a result of this contract termination payment, if any, will be recorded in the fourth quarter of 2025 when the amount of deferred revenue recognized will be known.

## NOTE 15 – LEASES

*Leasing Arrangements as Lessee*

We determine if an arrangement is a lease upon commencement of the contract. If an arrangement is determined to be a long-term lease (greater than 12 months), we recognize a right-of-use asset and lease liability based on the present value of the future minimum lease payments over the lease term at the commencement date. As most of our leases do not provide an implicit rate, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. Our lease terms may also include options to extend or terminate the lease when it is reasonably certain that we will exercise those options. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term. Right-of-use assets are included in other deferred charges, the current portion of lease liabilities is included in accrued expenses and the long-term portion of lease liabilities is included in other deferred credits and other liabilities on our consolidated statements of financial position.

We have elected to apply the short-term lease exception for contracts that have a lease term of twelve months or less and do not include an option to purchase the underlying asset. Therefore, we do not recognize a right-of-use asset or lease liability for such contracts. We recognize short-term lease payments as expense on a straight-line basis over the lease term. Variable lease payments that do not depend on an index or rate are recognized as expense.

**Operating Leases**

We have lease agreements as lessee for the right to use various facilities and operational assets. Rent expense for all short-term and long-term operating leases was $1.2 million for the three months ended June 30, 2025 and $0.7 million for the comparable period in 2024. Rent expense for all short-term and long-term operating leases was $2.4 million for the six months ended June 30, 2025 and $1.3 million for the comparable period in 2024. Rent expense is included in various categories of operating expenses on our consolidated statements of operations based on the type and purpose of the lease.

Our consolidated statements of financial position include the following lease components (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| **Operating leases:** | | |
| Operating lease right-of-use assets | $ 12,940 | $ 13,221 |
| Less: Accumulated amortization | (2,401) | (3,110) |
| **Net operating lease right-of-use assets** | **$ 10,539** | **$ 10,111** |
| | | |
| Operating lease liabilities - current | $ (630) | $ (332) |
| Operating lease liabilities - noncurrent | (6,015) | (5,703) |
| **Total operating lease liabilities** | **$ (6,645)** | **$ (6,035)** |
| | | |
| **Finance leases:** | | |
| Finance lease right-of-use assets | $ 95 | $ 95 |
| Less: Accumulated amortization | (51) | (29) |
| **Net finance lease right-of-use assets** | $ 44 | $ 66 |
| | | |
| Finance lease liabilities - current | $ (37) | $ (47) |
| Finance lease liabilities - noncurrent | — | (12) |
| **Total finance lease liabilities** | $ (37) | $ (59) |
| | | |
| **Lease Term and Discount Rate:** | | |
| **Weighted-average remaining lease term (in years)** | | |
| Operating leases | 29.2 | 32.8 |
| Finance leases | 1.0 | 1.5 |
| **Weighted-average discount rate** | | |
| Operating leases | 6.92 % | 6.93 % |
| Finance leases | 6.99% | 6.99% |

Future expected minimum lease commitments under operating leases are as follows (dollars in thousands):

| | Operating Leases | Finance Leases | Total |
|---|---|---|---|
| Year 1 | $ 1,175 | $ 38 | $ 1,213 |
| Year 2 | 792 | — | 792 |
| Year 3 | 627 | — | 627 |
| Year 4 | 555 | — | 555 |
| Year 5 | 432 | — | 432 |
| Thereafter | 12,112 | — | 12,112 |
| **Total lease payments** | **$ 15,693** | **$ 38** | **$ 15,731** |
| Less imputed interest | (9,048) | (1) | (9,049) |
| **Total** | **$ 6,645** | **$ 37** | **$ 6,682** |

*Leasing Arrangements as Lessor*

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $7.2 million and $4.7 million for the three months ended June 30, 2025 and 2024 and $14.5 million and $6.4 million for the six months ended June 30, 2025 are included in other operating revenue on our consolidated statements of operations.

In May 2024, the conditions for the effectiveness of a tolling agreement with a third party were satisfied for our two 70 MW units at our Knutson Generating Station for all capacity and energy through the operation of both units. In September 2024, we entered into a tolling agreement with a third party for one of our two 70 MW units at our Limon Generating Station for all capacity and energy through the operation of that unit that will commence in January 2026. In December 2024, we entered into a tolling agreement with a third party for one of our four 40 MW units at our Pyramid Generating Station for all capacity and energy through the operation of that unit that commenced in January 2025. In substance these agreements were determined to be leases in accordance with the accounting standards for leases as the third party has the right to the economic benefits of the asset and controls the use of the asset by its contractual rights, including the ability to direct the timing of dispatch of energy.

The lease arrangement with the Springerville Partnership is not reflected in our lease right right-of-use asset or liability balances as the associated revenues and expenses are eliminated in consolidation. See Note 17 - Variable Interest Entities. However, as the non-controlling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded.

**NOTE 16 – FAIR VALUE**

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal or in the most advantageous market when no principal market exists. The fair value measurement accounting guidance emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability (market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress). In considering market participant assumptions in fair value measurements, a three-tier fair value hierarchy for measuring fair value was established which prioritizes the inputs used in measuring fair value as follows:

Level 1 inputs are based upon quoted prices for identical instruments traded in active (exchange-traded) markets. Valuations are obtained from readily available pricing sources for market transactions (observable market data) involving identical assets or liabilities.

Level 2 inputs are based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active and model-based valuation techniques (such as option pricing models, discounted cash flow models) for which all significant assumptions are observable in the market.

Level 3 inputs consist of unobservable market data which is typically based on an entity's own assumptions of what a market participant would use in pricing an asset or liability as there is little, if any, related market activity.

In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. The assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified in Level 3.

*Executive Benefit Restoration Plan Trust*

We have an irrevocable trust with an independent third party to fund the NRECA Executive Benefit Restoration Plan. The trust is funded quarterly to the prior year obligation as determined by the NRECA actuary. The trust consists of investments in equity and debt securities and are measured at fair value on a recurring basis. Changes in the fair value of investments in equity securities are recognized in earnings and changes in fair value of investments in debt securities classified as available-for-sale are recognized in other comprehensive income until realized. The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our consolidated statements of financial position. The cost and fair values of our marketable securities are as follows (dollars in thousands):

| | June 30, 2025 | | December 31, 2024 | |
|---|---|---|---|---|
| | Cost | Estimated Fair Value | Cost | Estimated Fair Value |
| Marketable securities | $ 10,222 | $ 10,133 | $ 10,101 | $ 9,829 |

*Marketable Securities*

We hold marketable securities in connection with the directors' and executives' elective deferred compensation plans which consist of investments in stock funds, bond funds and money market funds. These securities are measured at fair value on a recurring basis with changes in fair value recognized in earnings. The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our consolidated statements of financial position. The cost and fair values of our marketable securities are as follows (dollars in thousands):

| | June 30, 2025 | | December 31, 2024 | |
|---|---|---|---|---|
| | Cost | Estimated Fair Value | Cost | Estimated Fair Value |
| Marketable securities | $ 588 | $ 611 | $ 582 | $ 587 |

*Cash Equivalents*

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $142.0 million as of June 30, 2025 and $182.0 million as of December 31, 2024.

*Debt*

The fair values of long-term debt, excluding amounts reclassified from short-term debt, were estimated using discounted cash flow analyses based on our current incremental borrowing rates for similar types of borrowing arrangements. These valuation assumptions utilize observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs). The principal amounts and fair values of our debt are as follows (dollars in thousands):

| | June 30, 2025 | | December 31, 2024 | |
|---|---|---|---|---|
| | Principal Amount | Estimated Fair Value | Principal Amount | Estimated Fair Value |
| Total long-term debt | $ 2,965,228 | $ 2,799,867 | $ 2,961,992 | $ 2,726,184 |

**NOTE 17 – VARIABLE INTEREST ENTITIES**

The following is a description of our financial interests in variable interest entities that we consider significant. This includes an entity for which we are determined to be the primary beneficiary and therefore consolidate.

*Consolidated Variable Interest Entity*

**Springerville Partnership:** We own a 51 percent equity interest, including the 1 percent general partner equity interest, in the Springerville Partnership, which is the 100 percent owner of Springerville Unit 3 Holding LLC ("Owner Lessor"). The Owner Lessor is the owner of the Springerville Unit 3. We, as general partner of the Springerville Partnership, have the full, exclusive and complete right, power and discretion to operate, manage and control the affairs of the Springerville Partnership and take certain actions necessary to maintain the Springerville Partnership in good standing without the consent of the limited partners. Additionally, the Owner Lessor has historically not demonstrated an ability to finance its activities without additional financial support. The financial support is provided by our remittance of lease payments in order to permit the Owner Lessor, the holder of the Springerville Unit 3 assets, to pay the debt obligations and equity returns of the Springerville Partnership. We have the primary risk (expense) exposure in operating the Springerville Unit 3 assets and are responsible for 100 percent of the operation, maintenance and capital expenditures of Springerville Unit 3 and the decisions related to those expenditures including budgeting, financing and dispatch of power. Based on all these facts, it was determined that we are the primary beneficiary of the Owner Lessor. Therefore, the Springerville Partnership and Owner Lessor have been consolidated by us.

Assets and liabilities of the Springerville Partnership that are included in our consolidated statements of financial position are as follows (dollars in thousands):

| | June 30, 2025 | December 31, 2024 |
|---|---|---|
| Net electric plant | $ 656,072 | $ 676,367 |
| Noncontrolling interest | 130,329 | 130,498 |
| Long-term debt | 172,479 | 172,790 |
| Accrued interest | 4,997 | 4,997 |

Our consolidated statements of operations include the following Springerville Partnership expenses for the three and six months ended June 30, 2025 and 2024 (dollars in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| Depreciation, amortization and depletion | $ 10,147 | $ 4,535 | $ 20,295 | $ 9,069 |
| Interest | 2,842 | 2,852 | 5,686 | 5,885 |

The revenue associated with the Springerville Partnership lease has been eliminated in consolidation. Income, losses and cash flows of the Springerville Partnership are allocated to the general and limited partners based on their equity ownership percentages. The net income or loss attributable to the 49 percent non-controlling equity interest in the Springerville Partnership is reflected on our consolidated statements of operations.

**NOTE 18 – LEGAL**

Other than as disclosed below or in our annual report on Form 10-K for the year ended December 31, 2024 filed with the SEC, we do not expect any litigation or proceeding pending or threatened against us to have a potential material effect on our financial condition, results of operations or cash flows.

*CTP Proceeding:* Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. On September 1, 2021, we filed with FERC a modified contract termination payment methodology tariff as Rate Schedule 281 that provides a process should a Utility Member elect to withdraw from membership in us and terminate its wholesale electric service contract, Docket No. ER21-2818. The tariff process includes requirements for a two-year notice and the payment to us of a contract termination payment. On October 29, 2021, FERC accepted our modified contract termination payment methodology, effective November 1, 2021, subject to refund. FERC set the matter for hearing and instituted a concurrent Federal Power Act ("FPA") section 206 proceeding to determine the justness and reasonableness of our modified methodology. On December 19, 2023, FERC issued an order adopting a modified balance sheet approach for the contract termination payment methodology ("FERC December 19 Order").

On January 18, 2024, we, United Power, and others filed requests for rehearing with FERC of the FERC December 19 Order. Our request for rehearing included disputing FERC's rejection of our lost revenue approach and also certain clarifications. On February 20, 2024, FERC issued a notice stating the parties' requests for rehearing were denied by operation of law, but FERC stated it will address the merits of the requests in a subsequent order. On March 28, 2024, we filed a petition for review of the FERC December 19 Order with the United States Court of Appeals for the Tenth Circuit ("10th Circuit Court of Appeals"), Case No. 24-9516. On April 8, 2024, United Power filed a petition for review of the FERC December 19 Order. United Power, MPEI, Northwest Rural Public Power District ("NRPPD"), Basin Electric Power Cooperative ("Basin"), and La Plata Electric Association, Inc. ("LPEA") have filed notices of interventions in our petition for review with the 10th Circuit Court of Appeals.

On May 23, 2024, FERC issued a substantive order on rehearing, which modified the discussion in, but sustained the results of, the FERC December 19 Order (“May 23 Order”). On May 31, 2024, we filed a petition for review of the May 23 Order, Case No. 24-9538, with the 10th Circuit Court of Appeals. On June 3, 2024, the 10th Circuit Court of Appeals issued an order partially consolidating the cases for purposes of briefing. Briefing is completed.

On January 25, 2024, we filed a revised Rate Schedule 281 with FERC with the contract termination methodology based upon the FERC December 19 Order. On March 29, 2024, FERC issued an order accepting our revised Rate Schedule 281, subject to further compliance filing, and established hearing and settlement judge procedures related to our sleeving administrative fee methodology set forth in our revised Rate Schedule 281. In April and June 2024, we submitted further revisions to Rate Schedule 281 as directed by FERC's March 2024 order and May 23 Order, respectively. On December 5, 2024, FERC issued an order on our compliance filings accepting our April 2024 and June 2024 revisions of Rate Schedule 281, subject to further compliance filing ("FERC December 2024 Order"). The FERC December 2024 Order addressed the calculation of the contract termination payment for Utility Members served in the Eastern Interconnection and referred to a provision in our Amended and Restated Wholesale Power Contract for the Eastern Interconnection with Basin ("Basin Eastern WPC") to inform our calculation of such amount. The FERC December 2024 Order also addressed the calculation of a transmission credit for withdrawing Utility Members in the Western Interconnection. We filed our fourth compliance filing based upon the FERC December 2024 Order with FERC on February 5, 2025. United Power and NRPPD filed protests to our fourth compliance filing and others filed comments.

We, NRPPD, and others filed requests for rehearing with FERC of the FERC December 2024 Order that were denied by operation of law. On February 12, 2025, we filed a petition for review of the FERC December 2024 Order, Case No. 25-9522, with the 10th Circuit Court of Appeals. On April 7, 2025, NRPPD also filed a petition for review of the FERC December 2024 Order with the 10th Circuit Court of Appeals. On May 23, 2025, NRPPD filed a stipulation to voluntarily dismiss its April 7 petition, which the court granted.

On April 29, 2025, FERC issued a substantive order on rehearing ("April 2025 Order") addressing requests for hearing and clarification of the FERC December 2024 Order. FERC's April 2025 Order clarified certain aspects of the calculation of the transmission credit for withdrawing Utility Members in the Western Interconnection including that debt associated with distribution facilities should be used in calculating the transmission-related debt.

On May 14, 2025, we filed a petition for review of the April 2025 Order, Case No. 25-9544, which is procedurally consolidated with Case No. 25-9522. On June 30, 2025, we filed our opening brief and thereafter Basin filed a supporting brief.

On May 29, 2025, we filed our fifth compliance filing of our Rate Schedule 281 based upon the April 2025 Order with FERC. United Power filed a protest to our fifth compliance filing, to which we answered.

On July 9, 2025, the 10th Circuit Court of Appeals issued an order on whether to consider hearing the cases during its September 2025 term of court or wait until its January 2026 term of court to hear all related petitions for review at the same time. The court invited all parties to file responses addressing this issue. We and the other parties either suggested or did not oppose waiting until the January 2026 term of court to hear all related petitions for review at the same time.

On August 4, 2025, FERC issued an order accepting our February 2025 fourth and May 2025 fifth compliance filings, subject to further compliance filing ("August 2025 Order"). FERC's August 2025 Order further clarified certain aspects of the calculation of the transmission credit for withdrawing Utility Members in the Western Interconnection including that an allocated amount of Other Non-Current Liabilities and Deferred Credits should be included in the calculation. We are evaluating the impact of the August 2025 Order, but expect the withdrawal related transmission credit for United Power and MPEI to further increase with a corresponding decrease in membership withdrawal income that was deferred as regulatory liabilities. The August 2025 Order also addressed the calculation of the contract termination payment for Utility Members served in the Eastern Interconnection with specific guidance on contacting Basin and the timing of providing the calculation to the withdrawing Utility Member. We are required to file an additional compliance filing of our Rate Schedule 281 based upon the August 2025 Order with FERC by September 3, 2025. We continue to evaluate FERC's August 2025 Order and next steps.

On May 6, 2025, we filed an Offer of Settlement and Settlement Agreement with FERC related to the sleeving administrative fee methodology set forth in Rate Schedule No. 281 for approval by FERC. FERC issued an order approving the settlement on July 9, 2025, and directed us to make a compliance filing with revised tariff records within 30 days of the order.

On May 1, 2024, United Power withdrew from membership in us and pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. United Power's contract termination payment amount was $709.4 million.

On February 1, 2025, MPEI withdrew from membership in us and pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. MPEI's contract termination payment amount was $86 million, including MPEI's pro rata share of our power purchase obligations in the Western Interconnection. MPEI paid us an exit fee in cash of $71.6 million and relinquished its right to any patronage capital in us resulting in a discounted patronage capital credit of $14.5 million. In May 2025, we trued-up MPEI's discounted patronage capital in accordance with Rate Schedule 281 and MPEI's Membership Withdrawal Agreement resulting in a payment to MPEI of $1 million that was made in June 2025.

As provided in the Membership Withdrawal Agreements with United Power and MPEI, United Power and MPEI's contract termination payments are also subject to true-up in the event Rate Schedule 281 and the amount paid are modified pursuant to a subsequent final and non-appealable FERC order, including resolution of the petitions for review.

It is not possible to predict the outcome of this matter or whether we will be required to refund any amounts to United Power or MPEI, if United Power or MPEI will be required to pay us any additional amounts, or the portion of the contract termination payment allocated to the transmission credit that will change based upon the August 2025 Order.

*NRPPD Section 206 Complaint:* On March 25, 2024, NRPPD filed an FPA section 206 proceeding with FERC, Docket No. EL24-93, against us and Basin seeking FERC to exercise primary jurisdiction over the interpretation of the FERC December 19 Order and the Basin Eastern WPC. In particular, NRPPD requested that FERC hold that NRPPD's withdrawal from us is permissible under the Basin Eastern WPC and that NRPPD's contract termination payment calculation is the appropriate contract termination payment. On May 8, 2024, we and Basin separately filed answers to NRPPD's complaint and requested FERC to deny NRPPD's complaint. On December 5, 2024, FERC issued an order denying NRPPD's complaint because NRPPD failed to satisfy its burden under FPA section 206. FERC's order also determined that NRPPD's withdrawal from us does not cause a breach of the Basin Eastern WPC ("FERC NRPPD Order"). On January 3, 2025, Basin filed a request for rehearing with FERC of the FERC NRPPD Order related to FERC's interpretation of the Basin Eastern WPC that NRPPD's withdrawal from us is not a breach of the Basin Eastern WPC. On February 3, 2025, FERC issued a notice stating the request for hearing was denied by operation of law. On February 13, 2025, Basin filed a petition for review of the FERC NRPPD Order, Case No. 25-1060, with the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit Court of Appeals"). On March 17, 2025, we filed a notice of intervention in Basin's petition for review in support of Basin.

On April 29, 2025, FERC issued a substantive order on rehearing addressing the complaint filed by NRPPD. The hearing order modified the discussion in, but sustained the results of, FERC's December 5, 2024 order. On May 19, 2025, Basin filed a petition for review of FERC's April 29, 2025 substantive order on rehearing with the DC Circuit Court of Appeals. FERC has moved to dismiss the petition arguing that Basin has no injury as NRPPD's complaint was dismissed.

*NRPPD v. Basin and Us:* On July 16, 2025, Basin made multiple filings with FERC stating that Basin is no longer a public utility under Part II of the FPA because it received funding from RUS under the Rural Electrification Act. Basin is seeking cancellation of the rate schedule filed with FERC concerning the Basin Eastern WPC. On July 18, 2025, NRPPD filed a complaint against Basin and us in the United States District Court, District of Nebraska, 4:25-cv-03153, seeking a declaratory judgment that the FERC NRPPD Order continues to bind Basin and us under the doctrines of res judicata and collateral estoppel despite Basin's assertion of it no longer being a public utility under Part II of the FPA. We are evaluating NRPPD's complaint. It is not possible to predict the outcome of this matter.

*Energy Sales - Soft-Cap:* In August 2020, we made certain energy sales to third parties in excess of the soft-cap price for short-term, spot market sales of $1,000 per megawatt hour established by the Western Electricity Coordinating Council. On October 7, 2020, we filed a report with FERC justifying the sales above the soft-cap and we did not recognize the revenue for the energy sales in excess of the soft-cap, Docket No. EL21-65-000. Based upon additional guidance from FERC, we filed a supplemental report on July 19, 2021. On May 20, 2022, FERC issued an order directing us to refund only certain amounts of the energy sales revenue in excess of the soft-cap. Based upon the FERC order, in the second quarter of 2022, we recognized approximately $2.9 million in excess of the soft-cap and refunded $0.4 million to a third party. On July 22, 2022, the California Public Utilities Commission filed a petition for review with the DC Circuit Court of Appeals of FERC's May 20, 2022 order, Case No. 22-1169. On August 18, 2022, we filed a motion to intervene with the DC Circuit Court of Appeals and an order granting said motion was issued on September 6, 2022. On January 24, 2023, the parties to the proceeding filed a motion with the court to consolidate this proceeding with other related proceedings with the DC Circuit Court of Appeals and proposed a procedural schedule with final briefings due in October 2023. On March 6, 2023, the DC Circuit Court of Appeals granted the motion to consolidate the proceedings. On July 9, 2024, the DC Circuit Court of Appeals issued an order vacating FERC's order and remanding the case back to FERC to conduct a *Mobile-Sierra* analysis. On July 15, 2025, FERC issued an order instituting a proceeding to consider whether the soft-cap should be eliminated. It is not possible to predict the outcome of this matter or whether we will be required to refund any additional amounts to third parties.

**NOTE 19 – SUBSEQUENT EVENT**

On August 7, 2025, we entered into a contract for a third-party to complete mine reclamation work at the Colowyo Mine. We are still evaluating the accounting impacts of this event.

## Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

### Overview

We are a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis. We were formed by our Utility Members for the purpose of providing wholesale power and transmission services to our Utility Members (which are distribution electric cooperatives and public power districts) for their resale of the power to their retail consumers. Our Utility Members serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our generated electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. Our Utility Members provide retail electric service to suburban and rural residences, farms and ranches, cities, towns and communities, as well as large and small businesses and industries.

We are owned entirely by our forty-three Members of which forty are Utility Members. Thirty-six of our Utility Members are not-for-profit, electric distribution cooperative associations. Four Utility Members are public power districts, which are political subdivisions of the State of Nebraska. We have three Non-Utility Members. We are regulated as a public utility under Part II of the FPA.

We supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or long-term purchase contracts with respect to various generating facilities. Our diverse generation portfolio provides us with maximum available power of 4,661 MWs, of which approximately 1,698 MWs comes from renewables.

We sold 8.1 million MWhs for the six months ended June 30, 2025, of which 82.0 percent was to Utility Members. Total revenue from electric sales was $606.6 million for the six months ended June 30, 2025 of which 84.7 percent was from Utility Member sales. Our results for the six months ended June 30, 2025 were primarily impacted by lower natural gas and market electric energy prices.

- Utility Member electric sales decreased $40.5 million, or 7.3 percent, primarily due to a decrease of 1,090,344 MWhs sold, or 14.2 percent, for the six months ended June 30, 2025 compared to the same period in 2024 due to the withdrawal of two former Utility Members. The impact of these withdrawals was offset by increased sales to our remaining Utility Members due to load growth and other factors.

- Non-member electric sales increased $18.5 million, or 24.9 percent, primarily due to higher long-term sales (in MWhs), offset by lower short-term sales. The ability to sell excess power to non-members after the withdrawal of two former Utility Members contributed significantly to the increase in non-member electric sales.

- Fuel expense decreased $20.2 million, or 18.6 percent, primarily due to a decrease in generation at both our coal and gas-fired facilities, as well as lower prices for coal.

### Wholesale Electric Service Contracts

Our Bylaws require each Utility Member, unless otherwise specified in a written agreement or the terms of the Bylaws, to purchase from us electric power and energy as provided in the Utility Member's contract with us. This contract is the wholesale electric service contract with each Utility Member, which is an all-requirements contract. Each wholesale electric service contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive, all energy and capacity required for the operation of the Utility Member's system, as modified by two programs (a self-supply percentage and our BYOR Program). Our wholesale electric service contracts with thirty-two of our Utility Members currently extend through 2066 and with the remaining eight Utility Members extending through 2050. Each Utility Member may elect to provide up a percent of its electric power requirements from distributed or renewable generation owned or controlled by the Utility Member. As of June 30, 2025, 20 Utility Members have enrolled in this program with capacity totaling approximately 93 MWs, of which 87 MWs are in operation.

In June 2025, we and a majority of our Utility Members separately entered into revised wholesale electric service contracts that were filed with FERC. In August 2025, FERC accepted such revised wholesale electric service contracts, with an August 6, 2025 effective date, subject to refund. FERC further set our revised wholesale electric service contracts for settlement and hearing procedures. The revised wholesale electric service contracts supersede the Utility Member's respective 2007 wholesale electric service contract. Thirty-two of our Utility Members' revised wholesale electric service contracts have an initial expiration date of December 31, 2066, with such Utility Members comprising 87.9 percent of our Utility Member revenue for the six months ended June 30, 2025, excluding former Utility Members and Utility Members that have provided a notice of intent to withdraw from membership in us. Four of our Utility Members' revised wholesale electric service contracts continue to have an initial expiration date of December 31, 2050. Four of our Utility Members elected not to sign the revised wholesale electric service contracts, and we will continue to sell and delivery to those Utility Members, and the Utility Members will continue to purchase and receive, under the Utility Members' 2007 wholesale electric service contract with an initial expiration date of December 31, 2050. Two of the Utility Members that elected not to sign the revised wholesale electric service contracts have provided us a notice of intent to withdraw from membership in us.

In June 2025, we also filed with FERC our revised Board Policy for Member System Distributed Resource Policy providing that a Utility Member may serve (self-supply) up to 20 percent of its requirements from distributed or renewable generation owned or controlled by the Utility Member. In June 2025, Basin filed a protest to our revised wholesale electric service contracts and our revised Board Policy related to the increase in the self-supply to 20 percent and asserting it violates our Amended and Restated Wholesale Power Contract for the Eastern Interconnection with Basin. We serve almost all of our Utility Members' load in the Eastern Interconnection through this contract and Basin alleges that permitting self-supply for this portion of our Member System load violates our contract with Basin. In August 2025, FERC accepted such revised Board Policy with an August 6, 2025 effective date, subject to refund. FERC further set our revised Board Policy for settlement and hearing procedures.

Our BYOR Program provides our Utility Members with the flexibility to build, own or contract for power supply projects while avoiding cost shifts amongst our Utility Members. Under the BYOR Program, Utility Members interested in participating in the BYOR Program will propose projects that they will own or control and that do not exceed 40 percent of their 2022 peak load during our peak period and which projects will not have an adverse impact on our reliability, overall system costs or compliance with environmental objectives as determined in accordance with our BYOR tariff. If a Utility Member-proposed resource is accepted following the program evaluation process, a Utility Member will enter into a flexible supply agreement enabling us to purchase the output of the BYOR project and that output will be deemed to serve the Utility Member's load. Our inaugural BYOR Program cycle was initiated in the third quarter of 2024. In June 2025, we executed flexible supply agreements with eleven Utility Members related to four BYOR projects totaling 330 MWs and filed the agreements with FERC. In August 2025, FERC accepted such flexible supply agreements. For further information on our BYOR Program, see "Item 1 – BUSINESS – MEMBERS" in our annual report on Form 10-K for the year ended December 31, 2024.

In August 2025, our Board approved a new tariff and pro forma agreement for high impact loads that have large load requirements, including data centers, into our system. This new tariff provides a repeatable process to address requests to serve large, high impact loads in the near term. We expect to file this high impact load tariff and related pro forma agreement with FERC in August 2025.

**Member Withdrawals and Relationship with Members**

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. In September 2021, we filed with FERC a modified contract termination payment methodology tariff as Rate Schedule 281 that provides a process should a Utility Member elect to withdraw from membership in us and terminate its wholesale electric service contract with us. The tariff process includes requirements for a two-year notice and the payment to us of a contract termination payment. In October 2021, FERC accepted our modified contract termination payment methodology, effective November 1, 2021, subject to refund. FERC set the matter for hearing and instituted a concurrent FPA section 206 proceeding to determine the justness and reasonableness of our modified methodology.

In December 2023, FERC issued an order adopting a modified balance sheet approach for the contract termination payment methodology. We have filed multiple revised Rate Schedule 281 with FERC as directed by FERC's compliance filing orders, including our latest revised Rate Schedule 281 that we filed in May 2025. For further information, see "Item 1 – BUSINESS – MEMBERS - Contract Termination Payment and Relationship with Members" in our annual report on Form 10-K for the year ended December 31, 2024 and Note 18 to the Unaudited Consolidated Financial Statements in Item 1.

On May 1, 2024, United Power withdrew from membership in us and pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. United Power's contract termination payment amount was $709.4 million. Our Board deferred a portion of the contract termination payment and a portion was related to a transmission credit that was deferred as required by FERC's orders on our Rate Schedule 281.

On February 1, 2025, MPEI withdrew from membership in us and pursuant to Rate Schedule 281 and a Membership Withdrawal Agreement terminated its wholesale electric service contract with us. MPEI's contract termination payment amount was $86 million, including MPEI's pro rata share of our power purchase obligations in the Western Interconnection. MPEI paid us an exit fee in cash of $71.6 million and relinquished its right to any patronage capital in us resulting in a discounted patronage capital credit of $14.5 million. Our Board deferred a portion of the contract termination payment and a portion was related to a transmission credit that was deferred as required by FERC's orders on our Rate Schedule 281.

The portion of the contract termination payment allocated to the transmission credit for both United Power and MPEI is subject to further change based upon FERC's August 2025 order of our February 2025 and May 2025 compliance filings related to Rate Schedule 281. For further information, see Note 18 to the Unaudited Consolidated Financial Statements in Item 1.

In March 2024, LPEA provided us a non-conditional notice to withdraw from membership in us, with an April 1, 2026, withdrawal effective date. In December 2024, NRPPD provided us a non-conditional notice of intent to withdraw, with a January 1, 2027, withdrawal effective date. We cannot predict if LPEA or NRPPD will withdraw from us and terminate their respective wholesale electric service contract early.

LPEA’s and NRPPD's estimated contract termination payments based upon the February 2025 version of Rate Schedule 281 are approximately $208 million and $13 million, respectively, prior to any adjustment related to the discounted patronage capital. LPEA's estimated contract termination payment does not include its pro rata share of our power purchase obligations in the Western Interconnection. NRPPD's estimated contract termination payment is our current estimate of the amount we are required to pay Basin under our wholesale power contract with Basin as a result of the Utility Member's withdrawal, subject to true-up after the amount is agreed to with Basin. LPEA and NRPPD comprised 7.1 percent of our Utility Member revenue and 4.8 percent of our operating revenue for the six months ended June 30, 2025.

Rate Schedule 281 and the contract termination payments are also subject to review and modification through proceedings currently pending with FERC and petitions for review filed in the federal courts. See Note 18 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

Consistent with prior withdrawals of Utility Members, we anticipate that some or all of LPEA's contract termination payment received may be deferred as regulatory liabilities, subject to our Board's discretion, and the contract termination payments from United Power, MPEI, and LPEA may be recognized as revenue in future periods to offset the revenue otherwise recoverable from Utility Members. We expect our non-member electric sales revenue and the amount of long-term energy sold to non-members to continue to increase in the future. See also “Item 1 – BUSINESS – MEMBERS - Contract Termination Payment and Relationship with Members” and "RISK FACTORS - Members and Regulatory Risks" in our annual report on Form 10-K for the year ended December 31, 2024.

**Colorado Electric Resource Plan and New Era Program**

***Colorado Electric Resource Plan***

In December 2023, we filed Phase I of our 2023 ERP with the COPUC, which included retirement of Craig Generating Station Unit 3 by January 1, 2028 and, if we receive New ERA Program funding and reach agreements with the applicable parties, our preferred plan retires Springerville Unit 3 by March 1, 2031. In September 2024, Phase II of our 2023 ERP was initiated with the issuance of three requests for proposals. In April 2025, we filed our 2023 ERP Implementation Report with the COPUC identifying our preferred portfolio of resources to be acquired during the period of 2026-2031. Phase II resource plan modeling indicated selection of the least-cost portfolio. The preferred portfolio adds 10 projects that result in 700 MWs of power purchase wind and solar, 650 MWs of contracted storage, and 307 MWs of owned gas, replaces the turbines at J.M. Shafer Generating Station to improve its capacity contributions, and maintains previously announced Craig Generating Station Unit 3 and Springerville Unit 3 retirement dates. In August 2025, the COPUC during an oral deliberation meeting determined that our preferred portfolio was the most cost-effective result from our Phase II ERP. We are still waiting for the written decision from the COPUC. For further information regarding our 2023 ERP, see “Item 1 – BUSINESS — POWER SUPPLY RESOURCES – Resource Planning” in our annual report on Form 10-K for the year ended December 31, 2024.

***New ERA Program***

In September 2023, we submitted a Letter of Interest to apply for a funding award of low-cost loans and grants through the New ERA Program, a $9.7 billion USDA program that is funded by the IRA. Our portfolio proposed in our Letter of Interest was the result of resource and financial modeling performed in connection with our preferred IRA scenario as part of Phase I of our 2023 ERP. In March 2024, we received an Invitation to Proceed from the USDA to complete the New ERA Program Application, and in June 2024, we submitted our Application. We have signed award commitment letters from USDA. In late March 2025, we were informed by the USDA that the New ERA Program had been released from agency review, during which time funding distribution had been paused. Although we completed the necessary steps to re-enter the agency’s queue for continuing to process our award, there can be no guarantee that USDA will continue to process our award, the timing of such processing and whether the scope and amounts of funds included in the award commitment letters will be remain the same and the timing of such disbursements, if any. For further information, see "Item 1 – BUSINESS — Overview" and "Item 1 – RISK FACTORS" in our annual report on Form 10-K for the year ended December 31, 2024.

**Solar Projects Construction**

Construction of the 145 MW Axial Basin Solar project, located in northwestern Colorado near the Colowyo Mine, continues to progress with module installation nearing completion. The Axial Basin Solar Substation has been energized and the facility has started to generate test energy. Construction of the 110 MW Dolores Canyon Solar project, located in southwestern Colorado, also continues to progress with module installation nearing completion and construction on the Dolores Canyon Solar Substation in progress.

Both projects are expected to achieve commercial operation in the fourth quarter of 2025. To the extent available, we also expect to utilize direct pay of federal tax benefits as provided in the IRA for both projects.

**Colowyo Mine Transition**

In September 2024, our Board approved a 2025 budget reflecting a decision to transition from mining to full reclamation at Colowyo Coal's Colowyo Mine in the latter part of 2025. During the six months ended June 30, 2025, we accelerated approximately $40.6 million in depreciation and amortization related to asset retirement obligations, development costs and depletion of coal reserves. We recognized deferred membership withdrawal income in an amount equal to such expenses resulting in no impact to our Utility Member's wholesale rate for 2025.

**Changing Environmental Regulations**

We are subject to extensive federal, state and local environmental requirements. The current federal administration is bringing about change in direction for federal environmental regulations. We are tracking environmental and permitting policy and proposed regulatory changes; however, it remains too early to tell what will survive expected legal challenges. To evaluate relevance, risk, and impact to our operations and plans, we are evaluating several recent proposals including the EPA's proposal to repeal the greenhouse gas standards, the EPA's proposal to repeal Mercury and Air Toxics Residual Risk and Technology Review- based requirements, and the EPA's proposal to partially disapprove Colorado's Regional Haze State Implementation Plan.

We obtained a Presidential Exemption for Craig Generating Station Units 2 and 3 from compliance requirements of the Mercury and Air Toxics Residual Risk and Technology Review rulemaking that was promulgated in 2024. This development enables us to avoid expenditures associated with requirements to install and operate particulate matter continuous emission monitoring systems starting July 8, 2027 and extending through the limited period prior to each units respective closure date, which is September 30, 2028 for Unit 2 and January 1, 2028 for Unit 3.

For further discussion regarding potential effects on our business from environmental regulations, see "Item 1 – BUSINESS — ENVIRONMENTAL REGULATION" and "Item 1 – RISK FACTORS" in our annual report on Form 10-K for the year ended December 31, 2024.

**Critical Accounting Policies**

The preparation of our financial statements in conformity with GAAP requires that our management make estimates and assumptions that affect the amounts reported in our consolidated financial statements. We base these estimates and assumptions on information available as of the date of the financial statements and they are not necessarily indicative of the results to be expected for the year. As of June 30, 2025, there were no material changes in our critical accounting policies as disclosed in our annual report on Form 10-K for the year ended December 31, 2024.

**Factors Affecting Results**

***Master Indenture***

As of June 30, 2025, we had approximately $2.9 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Our Master Indenture requires us to establish rates annually that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis and permits us to incur additional secured obligations as long as after giving effect to the additional secured obligation, we will continue to meet the DSR requirement on both a historical and pro forma basis. Our Master Indenture also requires us to maintain an ECR of at least 18 percent at the end of each fiscal year. Pursuant to our Master

Indenture, DSR and ECR are calculated based on unconsolidated Tri-State financials and calculated in accordance with the system of accounts proscribed by FERC, not GAAP.

***Margins and Patronage Capital***

We operate on a cooperative basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to meet certain financial requirements and to establish reasonable reserves. Revenues in excess of current period costs in any year are designated as net margins in our consolidated statements of operations. Net margins are treated as advances of capital by our Members and are allocated to our Utility Members on the basis of revenue from electricity purchases from us and to our Non-Utility Members as provided in their respective membership agreement.

Our Board Policy for Financial Goals and Capital Credits, approved and subject to change or waiver by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Members. On a periodic basis, our Board will determine whether to retire any patronage capital, and in what amounts, to our Members. As of June 30, 2025, we have retired approximately $669.1 million of patronage capital to our Members.

Our Board Policy for Financial Goals and Capital Credits includes three financial ratio goals for which we will set rates based upon an annual budget and true-up from the actual results of the previous fiscal year. The three financial goals are: (i) a minimum DSR of at least 1.15, (ii) a minimum ECR of at least 20 percent, and (iii) a minimum net margin attributable to us in each fiscal year of at least $20 million. Our Board Policy also provides that any extraordinary funds, such as contract termination payments, received by us will be used to offset future costs to our Utility Members. Extraordinary revenue will be recorded (a) in the year received to increase net margins, subject to loan agreement restrictions, (b) in the year received with the same amount of regulatory assets written off in the same fiscal year, resulting in no net change in net margins, or (c) deferred as a regulatory liability in the year received and recognized as revenue in future period or periods, with the oldest vintage year used first.

***Rates and Regulation***

Our electric sales revenues are derived from wholesale electric service sales to our Utility Members and non-member purchasers. Revenues from electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule filed with FERC. Revenues from wholesale electric power sales to our non-member purchasers is primarily pursuant to our market-based rate authority.

In May 2024, we filed with FERC a request to adopt a new Class A wholesale rate schedule (A-41) for electric power sales to our Utility Members. The wholesale rate maintains our postage stamp rate, with the same rate components for all our Utility Members, and incorporates a new formulary rate, which can be adjusted annually based on the budgets approved by our Board, including an annual true-up mechanism. In July 2024, FERC issued an order accepting our A-41 wholesale rate schedule, effective August 1, 2024, subject to refund. FERC further set our rate filing for settlement and hearing procedures. Settlement discussions on our A-41 wholesale rate schedule are ongoing and the hearing is held in abeyance. For further information, see “Item 1 – BUSINESS — RATE REGULATION” in our annual report on Form 10-K for the year ended December 31, 2024.

Our Class A rate schedule (A-41) for electric power sales to our Utility Members consist of eleven rate components, with three energy based and eight demand based. Our budget used to set our Utility Members' formula rate is set by our Board, consistent with the provision of reliable cost-based supply of electricity over the long term to our Utility Members. Energy is the physical electricity delivered to our Utility Members. The energy-based rates are billed based upon a price per kWh of physical energy delivered and the demand-based rates are billed based on the Utility Member’s highest thirty-minute integrated total demand measured in each monthly billing period during our peak period, Monday through Saturday, with the exception of six holidays.

Our Board may, from time to time, subject to FERC approval, create new regulatory assets or liabilities or modify the expected recovery period through rates of existing regulatory assets or liabilities.

***Tax Status***

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. We and our subsidiaries use the flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues.

**Results of Operations**

***General***

Our electric sales revenues are derived from wholesale electric service sales to our Utility Members and non-member purchasers. See "Factors Affecting Results – Rates and Regulation" for a description of our energy and demand rates to our Utility Members. Long-term contract sales to non-members generally include energy and demand components. Short-term sales to non-members are sold at market prices after consideration of incremental production costs. Demand billings to non-members are typically billed per kilowatt of capacity reserved or committed to that customer.

Weather has a significant effect on the usage of electricity by impacting both the electricity used per hour and the total peak demand for electricity. Consequently, weather has a significant impact on our revenues. Relatively higher summer or lower winter temperatures tend to increase the usage of electricity for heating, air conditioning and irrigation. Mild weather generally reduces the usage of electricity because heating, air conditioning and irrigation systems are operated less frequently. The amount of precipitation during the growing season (generally May through September) also impacts irrigation use. Other factors affecting our Utility Members' usage of electricity include:

- the amount, size and usage of machinery and electronic equipment;
- the expansion or contraction of operations among our Utility Members' commercial and industrial customers;
- the general growth in population; and
- economic conditions.

***Other Impacts***

Our ability to meet our Utility Members' electric power requirements and complete our capital projects are dependent on maintaining an efficient supply chain. The procurement and delivery of materials and equipment have been impacted by the current domestic and global supply chain disruptions. We are experiencing longer lead-times on the procurement of certain materials and equipment. Supply chain price inflation has contributed to lingering high prices for materials and equipment. Tariffs are a continuing area of concern. We have also received notice communications from vendors warning of upcoming price increases due to tariffs. The tariffs being put into place are far reaching and widespread, making it difficult for us and our suppliers to completely avoid or mitigate the impacts of higher costs throughout the supply chain. We continue to monitor potential impacts to our operations and estimated capital expenditures and timing of projects related to inflationary pressures, tariffs, and supply chain disruptions.

The recent enactment of the One Big Beautiful Bill Act may affect our business, financial condition, results of operation and future plans. Because the One Big Beautiful Bill Act is a wide reaching law, we are assessing its potential impact on our business, financial condition, results of operations and future plans and we plan to provide an update in future SEC filings once this assessment is complete.

**Three Months Ended June 30, 2025 Compared to Three Months Ended June 30, 2024**

***Operating Revenues***

Our operating revenues are primarily derived from electric power sales to our Utility Members and non-member purchasers. Other operating revenue consists primarily of wheeling, transmission, leasing, and coal sales. Other operating revenue also includes revenue we receive from certain of our Non-Utility Members. The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the three months ended June 30, 2025 and 2024 (dollars in thousands):

| | Three Months Ended June 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2025 | 2024 | Amount | Percent |
| **Operating revenues** | | | | |
| Utility Member electric sales | $ 257,649 | $ 258,286 | $ (637) | (0.2)% |
| Non-member electric sales | 44,497 | 38,768 | 5,729 | 14.8 % |
| Rate stabilization | 43,183 | 16,901 | 26,282 | 155.5 % |
| Provision for rate refunds | 5,273 | — | 5,273 | 100.0 % |
| Other | 39,525 | 23,544 | 15,981 | 67.9 % |
| **Total operating revenues** | **$ 390,127** | **$ 337,499** | **$ 52,628** | 15.6 % |
| | | | | |
| **Energy sales (in MWh):** | | | | |
| Utility Member electric sales | 3,231,954 | 3,528,944 | (296,990) | (8.4)% |
| Non-member electric sales | 693,077 | 628,456 | 64,621 | 10.3 % |
| | **3,925,031** | **4,157,400** | **(232,369)** | (5.6)% |

- Excluding United Power and MPEI, Utility Member load growth increased 21,399 MWhs, or 0.67 percent, during the three months ended June 30, 2025 compared to the same period in 2024. The impact of the United Power and MPEI membership withdrawals to total Utility Member electric sales (in dollars and MWhs) was lower than anticipated due to the load growth from our remaining Utility Members, and an increase in non-member electric sales.
- Non-member electric sales revenue increased primarily due to additional long-term sales and higher market prices. Long-term sales increased 113,557 MWhs to 469,733 MWhs for the three months ended June 30, 2025 compared to 356,176 MWhs for the same period in 2024 and average market prices were higher for the three months ended June 30, 2025 compared to the same period in 2024. The ability to sell excess power to non-members after United Power's and MPEI's membership withdrawals contributed significantly to the increase in non-member electric sales.
- We recognized $43.2 million of previously deferred membership withdrawal income during the three months ended June 30, 2025 as part of our rate stabilization measures compared to $16.9 million of deferred membership withdrawal income being recognized during the same period in 2024. The 2025 deferred membership withdrawal income includes $19.4 million of deferred membership withdrawal income to offset the expense recognition for accelerated expenses related to the transition from mining to full reclamation at the Colowyo Mine in the latter part of 2025 and $23.8 million in deferred membership withdrawal income related to rate stabilization measures in order to meet our financial ratios and goals. We expect to recognize additional previously deferred membership withdrawal income during the remainder of 2025.
- During 2025, we recorded a provision for rate refund related to FERC's orders on our Rate Schedule 281 (contract termination payment methodology) that addressed the calculation of a transmission credit for withdrawing Utility Members in the Western Interconnection. For further information, see Note 18 - Legal - CTP Proceeding to the Unaudited Consolidated Financial Statements in Item 1
- Other operating revenue increased primarily due to higher wheeling revenue, additional coal sales to third parties, and an increase in lease revenue related to two tolling agreements for three units at simple-cycle combustion turbines for all capacity and energy through the operation of such units.

***Operating Expenses***

Our operating expenses are primarily comprised of the costs that we incur to supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases and the costs associated with any sales of power to non-members.

The following is a summary of the components of our operating expenses for the three months ended June 30, 2025 and 2024 (dollars in thousands):

| | Three Months Ended June 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2025 | 2024 | Amount | Percent |
| **Operating expenses** | | | | |
| Purchased power | $ 110,405 | $ 98,840 | $ 11,565 | 11.7 % |
| Fuel | 36,543 | 32,208 | 4,335 | 13.5 % |
| Production | 37,686 | 47,057 | (9,371) | (19.9)% |
| Transmission | 41,869 | 44,964 | (3,095) | (6.9)% |
| General and administrative | 39,977 | 23,830 | 16,147 | 67.8 % |
| Depreciation, amortization and depletion | 71,154 | 44,152 | 27,002 | 61.2 % |
| Coal mining | 13,530 | 1,027 | 12,503 | 1,217.4 % |
| Other | 2,032 | 3,250 | (1,218) | (37.5)% |
| **Total operating expenses** | **$ 353,196** | **$ 295,328** | **$ 57,868** | 19.6 % |

- General and administrative expense increased primarily due to lower recoveries of general and administrative costs from joint project activities and an overall increase in expenses related to general and administrative labor and benefits.
- Depreciation, amortization and depletion expenses increased primarily due to accelerated depreciation and amortization from the transition from mining to reclamation at Colowyo Mine in the latter part of 2025. Additionally, depreciation, amortization and depletion was higher for the three months ended June 30, 2025 compared to the same period in 2024 due to depreciation rates that went into effect August 1, 2024 after issuance of the FERC order accepting our A-41 formula rate to our Utility Members.
- Coal mining expense increased primarily due to the transition from mining to reclamation at Colowyo Mine in the latter part of 2025.

**Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024**

***Operating Revenues***

The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the six months ended June 30, 2025 and 2024 (dollars in thousands):

| | Six Months Ended June 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2025 | 2024 | Amount | Percent |
| **Operating revenues** | | | | |
| Utility Member electric sales | $ 513,649 | $ 554,112 | $ (40,463) | (7.3)% |
| Non-member electric sales | 92,903 | 74,387 | 18,516 | 24.9 % |
| Rate stabilization | 88,126 | 16,901 | 71,225 | 421.4 % |
| Provision for rate refunds | 2,719 | — | 2,719 | 100.0 % |
| Other | 67,930 | 43,648 | 24,282 | 55.6 % |
| **Total operating revenues** | **765,327** | **689,048** | **$ 76,279** | 11.1 % |
| | | | | |
| **Energy sales (in MWh):** | | | | |
| Utility Member electric sales | 6,610,793 | 7,701,135 | (1,090,342) | (14.2)% |
| Non-member electric sales | 1,455,804 | 1,081,229 | 374,575 | 34.6 % |
| | **8,066,597** | **8,782,364** | **(715,767)** | (8.2)% |

- Excluding United Power and MPEI, Utility Member load growth increased 120,119 MWhs, or 1.86 percent, during the six months ended June 30, 2025 compared to the same period in 2024. The impact of the United Power and MPEI membership withdrawals to total Utility Member electric sales (in dollars and MWhs) was lower than anticipated due to the load growth from our remaining Utility Members, and an increase in non-member electric sales.
- Non-member electric sales increased primarily due to higher long-term sales. Long-term sales increased 425,649 MWhs, or 74.0 percent, to 1,000,755 MWhs for the six months ended June 30, 2025 compared to 575,106 MWhs for

the same period in 2024. The ability to sell excess power to non-members after United Power's and MPEI's membership withdrawals contributed significantly to the increase in non-member electric sales.

- We recognized $88.1 million of deferred membership withdrawal income during the six months ended June 30, 2025 compared to $16.9 million of deferred membership withdrawal during the same period in 2024 as part of our rate stabilization measures. The 2025 deferred membership withdrawal income includes $40.6 million in accelerated expenses related to the transition from mining to full reclamation at the Colowyo Mine in the latter part of 2025 and $47.5 million related to rate stabilization measures in order to meet our financial ratios and goals. We expect to recognize additional previously deferred membership withdrawal income during the remainder of 2025.
- Other operating revenue increased primarily due to higher wheeling revenue, higher coal sales to third parties and an increase in lease revenue related to two tolling agreements for three units at simple-cycle combustion turbines for all capacity and energy through the operation of such units during the six months ended June 30, 2025 compared to the same period in 2024.

***Operating Expenses***

The following is a summary of the components of our operating expenses for the six months ended June 30, 2025 and 2024 (dollars in thousands):

| | Six Months Ended June 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2025 | 2024 | Amount | Percent |
| **Operating expenses** | | | | |
| Purchased power | 207,549 | 191,910 | $ 15,639 | 8.1 % |
| Fuel | 88,343 | 108,548 | (20,205) | (18.6)% |
| Production | 74,180 | 89,183 | (15,003) | (16.8)% |
| Transmission | 85,959 | 92,522 | (6,563) | (7.1)% |
| General and administrative | 79,278 | 45,563 | 33,715 | 74.0 % |
| Depreciation, amortization and depletion | 143,935 | 88,776 | 55,159 | 62.1 % |
| Coal mining | 7,172 | 2,105 | 5,067 | 240.7 % |
| Other | 5,042 | 6,200 | (1,158) | (18.7)% |
| **Total operating expenses** | **$ 691,458** | **$ 624,807** | **$ 66,651** | 10.7 % |

- General and administrative expense increased primarily due to lower recoveries of general and administrative costs from joint project activities and an overall increase in expenses related to general and administrative labor and benefits.
- Depreciation, amortization and depletion expenses increased primarily due to accelerated depreciation and amortization from the transition from mining to reclamation at Colowyo Mine in the latter part of 2025. Additionally, depreciation, amortization and depletion was higher for the six months ended June 30, 2025 compared to the same period in 2024 due to depreciation rates that went into effect August 1, 2024 after issuance of the FERC order accepting our A-41 formula rate to our Utility Members.
- Coal mining expense increased primarily due to the transition from mining to reclamation at Colowyo Mine in the latter part of 2025.

**Financial Condition as of June 30, 2025 Compared to December 31, 2024**

The principal changes in our financial condition from December 31, 2024 to June 30, 2025 were due to increases and decreases in the following:

***Assets***

- Construction work in progress increased $55.6 million, or 15.1 percent, to $424.0 million as of June 30, 2025 compared to $368.4 million as of December 31, 2024. The increase was primarily due to capital expenditures for the Axial Basin and Dolores Canyon Solar projects and various transmission projects.

***Liabilities***

- Short-term borrowings increased $44.7 million to $44.8 million as of June 30, 2025 compared to $0.1 million as of December 31, 2024. The increase was due to issuance of commercial paper to support operating cash flow.

- Regulatory liabilities decreased $6.3 million to $490.7 million as of June 30, 2025 compared to $497.0 million as of December 31, 2024. The decrease was primarily due to the recognition of deferred membership withdrawal income of $88.1 million during the six month period ended June 30, 2025 partially offset by MPEI's $86.0 million contract termination payment amount arising from its withdrawal from membership in us and the termination of its wholesale electric service contract with us. The 2025 deferred membership withdrawal income includes $40.6 million in accelerated expenses related to the transition to full reclamation at the Colowyo Mine in the latter part of 2025 and $47.5 million related to rate stabilization measures in order to meet our financial ratios and goals.

**Liquidity and Capital Resources**

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of short-term and long-term borrowings. As of June 30, 2025, we had $181.5 million in cash and cash equivalents. Our committed credit arrangements as of June 30, 2025 are as follows (dollars in thousands):

| | Authorized Amount | Available June 30, 2025 |
|---|---|---|
| 2022 Revolving Credit Agreement | $ 520,000 (1) | $ 472,000 (2) |
| Renewable Revolving Credit Agreement (3) | $ 250,000 | $ 176,000 |

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.
(2) The portion of this facility that was unavailable as of June 30, 2025 was $48 million which was dedicated to support outstanding commercial paper and an outstanding letter of credit for the benefit of RUS as part of our loan agreement for the Rural Energy Savings Program.
(3) The proceeds from this facility are required to be used for eligible green investments, as defined in the Renewable Revolving Credit Agreement. The current eligible green investments include Axial Basin and Dolores Canyon Solar projects.

We have a secured 2022 Revolving Credit Agreement with aggregate commitments of $520 million. The 2022 Revolving Credit Agreement includes a swingline sublimit of $125 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million, of which $125 million of the swingline sublimit, $72 million of the letter of credit sublimit, and $455 million of the commercial paper back-up sublimit remained available as of June 30, 2025.

The 2022 Revolving Credit Agreement is secured under our Master Indenture and has a maturity date of April 25, 2027, unless extended as provided therein. Funds advanced under the 2022 Revolving Credit Agreement bear interest either at adjusted Term SOFR rates or alternative base rates, at our option. The adjusted Term SOFR rate is the Term SOFR rate for the term of the advance plus a margin (1.250 percent as of June 30, 2025) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (0.250 percent as of June 30, 2025) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00 percent, (b) the prime rate, and (c) the adjusted Term SOFR rate plus 1.00 percent.

Under our commercial paper program, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our 2022 Revolving Credit Agreement, which was $500 million as of June 30, 2025, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of June 30, 2025, we had $45 million commercial paper outstanding and $455 million available on the commercial paper back-up sublimit. See Note 8 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

As a requirement of a loan from RUS provided as part of the Rural Energy Savings Program and our Electrify and Save® On-Bill Repayment Program, we are required to maintain a letter of credit for the benefit of RUS, which is currently in the amount of $3 million.

On April 7, 2025, we used a portion of MPEI's contract termination payment proceeds to payoff the $40 million balance on our 2020 variable interest rate term loan with CFC.

On June 18, 2025, we entered into a Renewable Revolving Credit Agreement with CoBank as lead arranger and CFC as administrative agent, in the amount of $250 million. As of June 30, 2025, we had borrowed $74 million in adjusted Term SOFR rate loans under such facility and $176 million of availability remained.

The Renewable Revolving Credit Agreement is secured under our Master Indenture and has a maturity date of June 18, 2030. The proceeds from this facility are required to be used for eligible green investments, as defined in the Renewable

Revolving Credit Agreement. Funds advanced under the Renewable Revolving Credit Agreement bear interest at adjusted Term SOFR rates or alternative base rates, at our option. The adjusted Term SOFR rate is the Term SOFR rate for the term of the advance plus a margin (1.200 percent as of June 30, 2025) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (0.125 percent as of June 30, 2025) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00 percent, (b) the prime rate, and (c) the adjusted Term SOFR rate plus 1.00 percent.

The 2022 Revolving Credit Agreement and Renewable Revolving Credit Agreement contain customary representations, warranties, covenants, events of default and acceleration, including financial DSR and ECR requirements in line with the covenants contained in our Master Indenture. A violation of these covenants would result in the inability to borrow under the facilities.

We have previously purchased our outstanding debt through cash purchases in open market purchases. In the future, we may from time to time purchase additional outstanding debt through cash purchases and/or exchanges for other securities, in open market purchases, privately negotiated transactions, additional tender offers, or otherwise and may continue to seek to retire or purchase our outstanding debt in the future. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. We are mindful of our debt and its maturities and we continually evaluate options to ensure that our balance sheet and capital structure is aligned with our business and the long-term health of our company.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, restricted cash, our commercial paper program, the 2022 Revolving Credit Agreement, Renewable Revolving Credit Agreement, and contract termination payments from withdrawing Utility Members.

***Cash Flow***

Cash is provided by operating activities and issuance of debt. Capital expenditures and debt service payments comprise a significant use of cash.

**Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024**

*Operating activities*. Net cash provided by operating activities was $107.1 million for the six months ended June 30, 2025 compared to $743.6 million for the same period in 2024, a decrease in net cash provided by operating activities of $636.5 million. Cash provided by operating activities during 2025 was impacted by MPEI's contract termination payment of $86.0 million. Additionally, cash provided by operating activities was also impacted by the timing of cash collected from Member accounts receivable, payment of trade payables and accrued expenses.

*Investing activities*. Net cash used in investing activities was $182.2 million for the six months ended June 30, 2025 compared to $177.3 million for the same period in 2024, an increase in net cash used in investing activities of $4.9 million. The increase in net cash used in investing activities was impacted by construction costs for the Axial Basin Solar and Dolores Canyon Solar facilities and capital expenditures for various transmission and generation projects. Additionally, on February 1, 2025, we sold to MPEI certain assets for $5.9 million that were primarily used to serve MPEI's load.

*Financing activities*. Net cash provided by financing activities was $26.7 million for the six months ended June 30, 2025 compared to net cash used in financing activities of $392.8 million for the same period in 2024, an increase in net cash provided by financing activities of $419.5 million. The increase in net cash provided by financing activities was primarily due to $74 million of proceeds that we received in adjusted Term SOFR rate loans under our Renewable Revolving Credit Agreement and an increase in commercial paper issuances. Additionally, financing activities was impacted by a patronage capital retirement of $15.5 million resulting from MPEI's withdrawal, after true-up.

**Capital Expenditures**

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility closures, facility costs, market factors and other items affecting our forecasts. In the years 2025 through 2027, we forecast that we may invest approximately $1.46 billion in new facilities and upgrades to our existing facilities.

Our actual capital expenditures depend on a variety of factors, including assumptions related to our 2023 ERP, receipt of New ERA Program funding and other federal programs, Utility Member load growth or Utility Member withdraws, BYOR Program, availability of necessary permits, regulatory changes, environmental requirements, inflation, tariffs, construction delays and costs, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

Capital projects include several transmission projects to improve reliability and load-serving capability throughout our service area.

**Rating Triggers**

Our current senior secured ratings are “Baa1 (stable outlook)” by Moody’s, “BBB (stable outlook)” by S&P, and “BBB+ (stable outlook)” by Fitch. Our current short-term ratings are “A-2” by S&P and “F1” by Fitch.

Our 2022 Revolving Credit Agreement includes a pricing grid related to the Term SOFR spread, commitment fee and letter of credit fees due under the facility. Our Renewable Revolving Credit Agreement includes a pricing grid related to the Term SOFR spread and commitment fee. Certain of our other loan agreements also include a pricing grid related to the Term SOFR spread. A downgrade of our senior secured ratings could result in an increase in each of these pricing components. We do not believe that any such increase would have a material adverse effect on our financial condition or our future results of operations. However, a downgrade of our senior secured ratings could impact the costs associated with incurring additional debt and could make accessing the debt markets on favorable terms more difficult.

We currently have contracts and other obligations that require adequate assurance of performance. These include organized markets contracts, power contracts, natural gas supply contracts and financial risk management contracts. Some of the contracts are directly tied to us maintaining investment grade credit ratings by S&P and Moody’s. We may enter into additional contracts which may contain adequate assurance requirements. If we are required to provide adequate assurances, it may impact our liquidity and the amount of adequate assurance required will be dependent on our credit ratings.

**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

There have been no material changes to market risks during the most recent fiscal quarter from those reported in our annual report on Form 10-K for the year ended December 31, 2024.

**Item 4. Controls and Procedures**

*Evaluation of Disclosure Controls and Procedures*

As of the end of the period covered by this report, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective.

*Changes in Internal Controls*

There have been no changes in our internal controls over financial reporting that occurred during the most recent fiscal quarter ended June 30, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

**PART II. OTHER INFORMATION**

**Item 1. Legal Proceedings**

Information required by this Item is contained in Note 18 to the Unaudited Consolidated Financial Statements in Item 1.

**Item 4. Mine Safety Disclosures**

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this quarterly report on Form 10-Q.

**Item 6. Exhibits**

| Exhibit Number | Description of Exhibit |
|---|---|
| 4.1.10 | Supplemental Master Mortgage Indenture No. 48, dated and effective as of June 18, 2025, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee. |
| 31.1 | Rule 13a-14(a)/15d-14(a) Certification, by Duane Highley (Principal Executive Officer). |
| 31.2 | Rule 13a-14(a)/15d-14(a) Certification, by Clifton Karnei (Principal Financial Officer). |
| 32.1 | Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Duane Highley (Principal Executive Officer). |
| 32.2 | Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Clifton Karnei (Principal Financial Officer). |
| 95 | Mine Safety Disclosure Exhibit. |
| 101 | XBRL Interactive Data File. |

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Tri-State Generation and Transmission Association, Inc.

| | | |
|---|---|---|
| Date: August 8, 2025 | By: | /s/ Duane Highley |
| | | Duane Highley |
| | | Chief Executive Officer |
| Date: August 8, 2025 | | /s/ Clifton Karnei |
| | | Clifton Karnei |
| | | Interim Chief Financial Officer (Principal Financial Officer) |