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, 2024
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, 2024

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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
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Basin	Basin Electric Power Cooperative
Board	Board of Directors
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
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
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	U.S. Department of Agriculture's Empowering Rural America Program
OATT	Open Access Transmission Tariff
Phase I 2023 ERP	Phase I of our 2023 Electric Resource Plan filed with the COPUC
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.
Utility Members	our electric distribution member systems, consisting of both Class A members and Class B members

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, 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, 2024	December 31, 2023
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,673,803	$ 5,722,679
Construction work in progress	256,301	163,954
Total electric plant	**5,930,104**	**5,886,633**
Less allowances for depreciation and amortization	(2,772,281)	(2,739,924)
Net electric plant	**3,157,823**	**3,146,709**
Other plant	950,982	952,318
Less allowances for depreciation, amortization and depletion	(726,882)	(711,896)
Net other plant	**224,100**	**240,422**
Total property, plant and equipment	**3,381,923**	**3,387,131**
Other assets and investments		
Investments in other associations	185,673	187,684
Investments in and advances to coal mines	1,715	1,619
Restricted cash and investments	172,252	3,408
Other noncurrent assets	14,579	15,264
Total other assets and investments	**374,219**	**207,975**
Current assets		
Cash and cash equivalents	110,498	106,005
Restricted cash and investments	697	605
Short-term investments	95,000	—
Deposits and advances	79,102	37,455
Accounts receivable—Utility Members	93,883	101,394
Other accounts receivable	27,446	23,123
Coal inventory	71,083	54,979
Materials and supplies	110,450	106,893
Total current assets	**588,159**	**430,454**
Deferred charges		
Regulatory assets	903,354	919,483
Prepayment—NRECA Retirement Security Plan	2,686	5,372
Other	56,579	36,121
Total deferred charges	**962,619**	**960,976**
Total assets	**$ 5,306,920**	**$ 4,986,536**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 887,861	$ 984,581
Accumulated other comprehensive loss	(801)	(839)
Noncontrolling interest	129,738	134,269
Total equity	**1,016,798**	**1,118,011**
Long-term debt	2,706,512	2,896,506
Total capitalization	**3,723,310**	**4,014,517**
Current liabilities		
Utility Member advances	10,656	14,333
Accounts payable	151,507	123,674
Short-term borrowings	116,101	184,305
Accrued expenses	34,317	39,268
Current asset retirement obligations	18,822	21,635
Accrued interest	22,545	24,549
Accrued property taxes	20,437	31,986
Current maturities of long-term debt	191,729	223,523
Total current liabilities	**566,114**	**663,273**
Deferred credits and other liabilities		
Regulatory liabilities	693,835	2,317
Deferred income tax liability	15,223	15,223
Asset retirement and environmental reclamation obligations	202,982	195,566
Other	94,623	84,125
Total deferred credits and other liabilities	**1,006,663**	**297,231**
Accumulated postretirement benefit and postemployment obligations	10,833	11,515
Total equity and liabilities	**$ 5,306,920**	**$ 4,986,536**

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,	
	2024	**2023**	**2024**	**2023**
Operating revenues				
Utility Member electric sales	$ 258,286	$ 274,225	$ 554,112	$ 566,401
Non-member electric sales	38,768	18,486	74,387	60,436
Rate stabilization	16,901	11,064	16,901	22,821
Provision for rate refunds	—	(6)	—	304
Other	23,544	14,686	43,648	32,544
	337,499	**318,455**	**689,048**	**682,506**
Operating expenses				
Purchased power	98,840	95,281	191,910	196,106
Fuel	32,208	44,773	108,548	126,703
Production	47,057	54,423	89,183	97,975
Transmission	44,964	46,280	92,522	95,308
General and administrative	23,830	23,577	45,563	42,075
Depreciation, amortization and depletion	44,152	42,690	88,776	85,071
Coal mining	1,027	4,130	2,105	5,769
Other	3,250	2,417	6,200	8,712
	295,328	**313,571**	**624,807**	**657,719**
Operating margins	**42,171**	**4,884**	**64,241**	**24,787**
Other income				
Interest	4,941	1,480	6,440	2,810
Capital credits from cooperatives	—	6	1,281	1,958
Other income	(1,197)	487	4,123	2,042
	3,744	**1,973**	**11,844**	**6,810**
Interest expense				
Interest	45,379	42,602	89,705	83,366
Interest charged during construction	(2,765)	(1,107)	(4,597)	(2,090)
	42,614	**41,495**	**85,108**	**81,276**
Income tax expense	—	23	—	45
Net margins including noncontrolling interest	**3,301**	**(34,661)**	**(9,023)**	**(49,724)**
Net margin attributable to noncontrolling interest	(2,793)	(2,524)	(5,497)	(4,918)
Net margins attributable to the Association	**$ 508**	**$ (37,185)**	**$ (14,520)**	**$ (54,642)**

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,	
	2024	**2023**	**2024**	**2023**
Net margins including noncontrolling interest	$ 3,301	$ (34,661)	$ (9,023)	$ (49,724)
Other comprehensive income (loss):				
Unrealized gain (loss) on securities available for sale	55	(45)	65	16
Amortization of prior service credit on postretirement benefit obligation included in net margin	(127)	(410)	(536)	(819)
Amortization of prior service cost on executive benefit restoration obligation included in net margin	220	289	509	578
Other comprehensive income (loss)	**148**	**(166)**	**38**	**(225)**
Comprehensive income (loss) including noncontrolling interest	**3,449**	**(34,827)**	**(8,985)**	**(49,949)**
Net comprehensive income attributable to noncontrolling interest	(2,793)	(2,524)	(5,497)	(4,918)
Comprehensive income (loss) attributable to the Association	**$ 656**	**$ (37,351)**	**$ (14,482)**	**$ (54,867)**

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,	
	2024	**2023**	**2024**	**2023**
Patronage capital equity at beginning of period	$ 969,553	$ 967,408	$ 984,581	$ 984,865
Net margins attributable to the Association	508	(37,185)	(14,520)	(54,642)
Retirement of patronage capital	(82,200)	—	(82,200)	—
Patronage capital equity at end of period	**887,861**	**930,223**	**887,861**	**930,223**
Accumulated other comprehensive loss at beginning of period	(949)	(527)	(839)	(468)
Unrealized gain on securities available for sale	55	(45)	65	16
Reclassification adjustment of prior service credit on postretirement benefit obligation included in net margin	(127)	(410)	(536)	(819)
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	220	289	509	578
Accumulated other comprehensive loss at end of period	**(801)**	**(693)**	**(801)**	**(693)**
Noncontrolling interest at beginning of period	126,945	127,625	134,269	126,180
Net comprehensive income attributable to noncontrolling interest	2,793	2,524	5,497	4,918
Equity distribution to noncontrolling interest	—	—	(10,028)	(949)
Noncontrolling interest at end of period	**129,738**	**130,149**	**129,738**	**130,149**
Total equity at end of period	**$ 1,016,798**	**$ 1,059,679**	**$ 1,016,798**	**$ 1,059,679**

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,	
	2024	**2023**
Operating activities		
Net margins including noncontrolling interest	$ (9,023)	$ (49,724)
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	88,776	85,071
Amortization of NRECA Retirement Security Plan prepayment	2,686	2,686
Amortization of debt issuance costs	1,462	1,178
Deposits associated with generator interconnection requests	9,932	11,127
Rate stabilization revenue	(16,901)	(22,821)
Capital credit allocations from cooperatives and income from coal mines under refund distributions	1,914	1,466
Changes in operating assets and liabilities:		
Accounts receivable	3,188	24,901
Coal inventory	(16,105)	(9,711)
Materials and supplies	(3,557)	(10,505)
Accounts payable and accrued expenses	(527)	(15,617)
Accrued interest	(2,004)	(2,479)
Accrued property taxes	(11,548)	(15,134)
Deferred membership withdrawal	709,395	—
Other	(14,101)	6,459
Net cash provided by operating activities	**743,587**	**6,897**
Investing activities		
Purchases of plant	(155,210)	(80,920)
Sale of electric plant	75,000	—
Sale of non-utility assets	3,136	—
Purchase of investments	(95,000)	—
Changes in deferred charges	(5,245)	443
Net cash used in investing activities	**(177,319)**	**(80,477)**
Financing activities		
Changes in Member advances	(3,677)	(272)
Payments of long-term debt	(222,881)	(69,005)
Proceeds from issuance of long-term debt	—	450,000
Debt issuance costs	(8)	(605)
Change in short-term borrowings, net	(68,304)	(273,502)
Retirement of patronage capital	(87,414)	(5,446)
Equity distribution to noncontrolling interest	(10,028)	(949)
Other	(527)	(482)
Net cash provided by (used in) financing activities	**(392,839)**	**99,739**
Net increase in cash, cash equivalents and restricted cash and investments	**173,429**	**26,159**
Cash, cash equivalents and restricted cash and investments – beginning	**110,018**	**110,682**
Cash, cash equivalents and restricted cash and investments – ending	**$ 283,447**	**$ 136,841**
Supplemental cash flow information:		
Cash paid for interest	$ 86,937	$ 83,477
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (2,769)	$ (1,169)

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, 2024 and 2023

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, 2023 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, 2024, results of operations for the three and six months ended June 30, 2024 and 2023, and cash flows for the six months ended June 30, 2024 and 2023 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 three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and non-utility members. We have forty-one electric distribution member systems who are Class A members to which we provided electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members. We have three non-utility members ("Non-Utility Members"). Our Class A members and any Class B members are collectively referred to as our "Utility Members." Our Class A members, any Class B members, and Non-Utility Members are collectively referred to as our "Members." Our rates are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). On December 23, 2019, our stated rate (A-40) to our Class A members was filed at FERC and was accepted by FERC on March 20, 2020. On August 2, 2021, FERC approved our settlement agreement related to our stated rate to our Class A members. On July 30, 2024, FERC issued an order accepting our A-41 formula rate to our Class A members, effective August 1, 2024, subject to refund. FERC further set our A-41 rate filing for settlement and hearing procedures and confirmed our accounting treatment, including amortization, and creation of regulatory assets for Escalante Generating Station, Rifle Generating Station, Craig Generating Station Units 2 and 3 and the New Horizon Mine environmental obligation. However, FERC did not currently authorize us to recover the regulatory assets that represent acquisition costs/goodwill for J.M Shafer Generating Station and Colowyo Coal Company LP ("Colowyo Coal"), with an aggregate balance of $68.9 million as of June 30, 2024. These costs were on our books prior to us becoming subject to FERC's jurisdiction. FERC stated in its order accepting our A-41 rate schedule that we did not request express authorization to recover acquisition costs including goodwill in our rates. We are evaluating next steps regarding these costs.

On May 1, 2024, United Power, Inc. ("United Power") withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to Rate Schedule 281 (contract termination payment methodology) on-file with FERC and a Membership Withdrawal Agreement with United Power. United Power's contract termination payment amount was $709.4 million. United Power paid us an exit fee in cash of $627.2 million, after a regulatory liabilities credit and United Power relinquishing its right to any patronage capital in us resulting in a discounted patronage capital credit of $82.2 million. Such amounts remain subject to true up in accordance with Rate Schedule 281 and United Power's Membership Withdrawal Agreement. On May 8, 2024, we also sold to United Power certain assets for $75.0 million that were primarily used to serve United Power's load after our receipt of approval from FERC on May 1, 2024. Of the total contract termination payment, $530.1 million was membership withdrawal that was deferred as a regulatory liability. The remaining $179.3 million of United Power's contract termination payment related to a transmission credit for the portion of transmission debt allocated to United Power that was deferred as required by FERC's order on our Rate Schedule 281. For the fiscal year 2023 and the six months ended June 30, 2024, United Power constituted 19.7 percent and 13.7 percent, respectively, of our revenue from our Utility Member sales.

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 December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update (“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. Expected recovery of deferred costs and returning deferred credits are based on specific ratemaking decisions by FERC or precedent for each item. 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.

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

	June 30, 2024	December 31, 2023
Regulatory assets		
Deferred income tax expense (1)	$ 15,223	$ 15,223
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	73,406	74,551
Acquisition costs – J.M. Shafer (3)	36,325	37,749
Acquisition costs – Colowyo Coal (4)	32,545	33,062
Deferred debt prepayment transaction costs (5)	102,103	106,417
Deferred Holcomb expansion impairment loss (6)	72,458	74,795
New Horizon Mine environmental obligation (7)	44,869	44,869
Unrecovered plant (8)	526,425	532,817
Total regulatory assets	**903,354**	**919,483**
Regulatory liabilities		
Interest rate swap - realized gain (9) and other	1,625	1,854
Membership withdrawal (10)	513,699	463
Withdrawal related transmission credit (11)	178,511	—
Total regulatory liabilities	**693,835**	**2,317**
Net regulatory asset	**$ 209,519**	**$ 917,166**

(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 acquisition costs related to our acquisition of an entity that owned J.M. Shafer Generating Station in December 2011. Acquisition costs are being amortized to depreciation, amortization and depletion expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Utility Members through rates.

(4) Represents acquisition costs related to our acquisition of Colowyo Coal in December 2011. Acquisition costs are being amortized to depreciation, amortization and depletion expense in the amount of $1.0 million annually through the 44-year period ending in 2056 and recovered from our Utility Members through rates.

(5) 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.

(6) 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.

(7) 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 will be amortized to expense in the amount of $1.8 million annually over 25 years.

(8) 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 and concluded the impairment of incurred costs is probable of recovery through future rates. 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. 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.

(9) 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.

(10) 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 May 1, 2024, United Power withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement. United Power's contract termination payment amount was $709.4 million, of which $530.1 million was membership withdrawal that was deferred by our Board as a regulatory liability. 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.

(11) Represents the remaining $179.3 million of United Power's transmission credit 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 order on Rate Schedule 281. The transmission credit, plus interest at FERC's prescribed interest rate, is refunded to the withdrawing member on a monthly basis if the withdrawing member takes transmission service from us and amortized on a straight-line basis over the remaining term. If the withdrawing member's transmission bill for a given month is lower than the credit amount that would be due, the difference is forfeited by the withdrawing 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, 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	0.89 %	to	6.27 %	$ 3,089,810	$ (1,699,258)	$ 1,390,552
Transmission plant	1.11 %	to	2.09 %	1,895,240	(701,422)	1,193,818
General plant	1.46 %	to	9.53 %	448,016	(274,586)	173,430
Other	2.75 %	to	10.00 %	240,737	(97,015)	143,722
Electric plant in service (at cost)				**$ 5,673,803**	**$ (2,772,281)**	**2,901,522**
Construction work in progress						256,301
Electric plant						**$ 3,157,823**

In March 2024, we executed an asset purchase agreement to purchase the 145 MW Axial Basin Solar project being developed in northwestern Colorado. Concurrent with execution of the purchase agreement, we also executed an engineering, procurement and construction contract with an affiliate of the developer of the project. In April 2024, we closed on the acquisition of Axial Basin Solar project and issued a notice to proceed with construction to the contractor.

In April 2024, we executed an asset purchase agreement to purchase the 110 MW Dolores Canyon Solar project being developed in southwestern Colorado. Concurrent with execution of the purchase agreement, we also executed an engineering, procurement and construction contract with an affiliate of the developer of the project. In May 2024, we closed on the acquisition of Dolores Canyon Solar project and issued a notice to proceed with construction to the contractor.

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 as of June 30, 2024. Both projects are expected to achieve commercial operation in the second half of 2025.

As of December 31, 2023, 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	0.89 %	to	6.27 %	$ 3,082,133	$ (1,669,941)	$ 1,412,192
Transmission plant	1.11 %	to	2.09 %	1,983,629	(708,412)	1,275,217
General plant	1.46 %	to	9.53 %	410,856	(266,013)	144,843
Other	2.75 %	to	10.00 %	246,061	(95,558)	150,503
Electric plant in service (at cost)				**$ 5,722,679**	**$ (2,739,924)**	**2,982,755**
Construction work in progress						163,954
Electric plant						**$ 3,146,709**

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of June 30, 2024 (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	$ 362,750	$ —
MBPP - Laramie River Station	28.50 %	537,127	349,594	7,047
Total		**$ 929,637**	**$ 712,344**	**$ 7,047**

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, 2024	December 31, 2023
Colowyo Mine assets	$ 395,438	$ 396,441
New Horizon Mine assets	6,320	6,448
Accumulated depreciation and depletion	(199,278)	(184,239)
Net mine assets	**202,480**	**218,650**
Non-utility assets	549,224	549,430
Accumulated depreciation	(527,604)	(527,658)
Net non-utility assets	**21,620**	**21,772**
Net other plant	**$ 224,100**	**$ 240,422**

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, 2024	December 31, 2023
Basin Electric Power Cooperative	$ 135,652	$ 135,652
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,451	12,451
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,054	15,054
CoBank, ACB	16,946	18,809
Other	5,570	5,718
Investments in other associations	**$ 185,673**	**$ 187,684**

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, 2024 or during 2023.

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, 2024	December 31, 2023
Cash and cash equivalents	$ 110,498	$ 106,005
Restricted cash and investments - current	697	605
Restricted cash and investments - noncurrent (1)	172,252	3,408
Cash, cash equivalents and restricted cash and investments	**$ 283,447**	**$ 110,018**

(1) The increase in restricted cash and investments - noncurrent was primarily related to the contract termination payment, which was restricted by contract.

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, 2024, we recognized $0.6 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, 2024	December 31, 2023
Accounts receivable - Utility Members	**$ 93,883**	**$ 101,394**
Other accounts receivable - trade:		
Non-member electric sales	16,048	9,657
Other	11,279	11,077
Total other accounts receivable - trade	**27,327**	**20,734**
Other accounts receivable - nontrade	119	2,389
Total other accounts receivable	**$ 27,446**	**$ 23,123**
Contract liabilities (unearned revenue)	**$ 3,589**	**$ 4,159**

NOTE 7 – OTHER DEFERRED CHARGES

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

	June 30, 2024	December 31, 2023
Preliminary surveys and investigations	$ 14,980	$ 12,845
Advances to operating agents of jointly owned facilities	7,995	2,750
Operating lease right-of-use assets	10,319	6,477
Other	23,285	14,049
Total other deferred charges	**$ 56,579**	**$ 36,121**

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 $2.7 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, 2024, we had $404 million in availability (including $384 million under the commercial paper back-up sublimit) under the 2022 Revolving Credit Agreement.

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

	June 30, 2024	December 31, 2023
Total debt	$ 2,914,553	$ 3,137,534
Less debt issuance costs	(18,269)	(19,723)
Less debt discounts	(8,531)	(8,678)
Plus debt premiums	10,488	10,896
Total debt adjusted for debt issuance costs, discounts and premiums	**2,898,241**	**3,120,029**
Less current maturities	(191,729)	(223,523)
Long-term debt	**$ 2,706,512**	**$ 2,896,506**

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, 2024	December 31, 2023
Commercial paper outstanding, net of discounts	$ 116,001	$ 184,205
Short-term borrowings - other	$ 100	$ 100
Weighted average interest rate	5.51 %	5.62 %

As of June 30, 2024, we had $116 million commercial paper outstanding and $384 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 RECLAMATION OBLIGATIONS

We account for current obligations associated with the future retirement of tangible long-lived assets and environmental reclamation 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 reclamation 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 reclamation obligations are as follows (dollars in thousands):

	Six Months Ended June 30, 2024
Obligations at beginning of period	$ 217,201
Liabilities incurred	3,456
Liabilities settled	(2,450)
Accretion expense	3,597
Total obligations at end of period	**$ 221,804**
Less current obligations at end of period	(18,822)
Long-term obligations at end of period	**$ 202,982**

The New Horizon Mine environmental remediation liability is $67.3 million as of June 30, 2024. Of this amount, $36.8 million is recorded on a discounted basis, using a discount rate of 3.25 percent, with total estimated undiscounted future cash outflows of $57.9 million. Environmental obligation expense is included in other operating expenses on our consolidated statements of operations. 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.

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, 2024	December 31, 2023
Transmission easements	$ 17,949	$ 17,862
OATT deposits	38,059	27,872
Financial liabilities - reclamation	12,564	16,895
Customer deposits	13,251	12,091
Contract liabilities (unearned revenue) - noncurrent	2,871	3,125
Operating lease liabilities - noncurrent	5,461	1,396
Other	4,468	4,884
Total other deferred credits and other liabilities	**$ 94,623**	**$ 84,125**

In 2015, we renewed transmission right-of-way easements on tribal nation lands where certain of our electric transmission lines are located. $26.1 million will be paid by us for these easements from 2024 through the individual easement terms ending between 2035 and 2047. The present values for the remaining easement payments were $17.9 million as of June 30, 2024 and December 31, 2023 which are recorded as other deferred credits and other liabilities.

OATT deposits represent refundable transmission customer deposits related to interconnection and transmission requests from third parties. An OATT deposit is refundable should the interconnection or transmission request not move forward.

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, 2024, 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, 2024
Postretirement medical benefit obligation at beginning of period	$ 924
Interest cost	29
Benefit payments (net of contributions by participants)	(180)
Postretirement medical benefit obligation at end of period	**$ 773**
Postemployment medical benefit obligation at end of period	243
Total postretirement and postemployment medical obligations at end of period	**$ 1,016**

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, 2024
Amounts included in accumulated other comprehensive income at beginning of period	$ 1,114
Amortization of prior service credit into other income	(536)
Amounts included in accumulated other comprehensive income at end of period	**$ 578**

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, 2024	
Executive benefit restoration obligation at beginning of period	$	10,158
Service cost		148
Interest cost		220
Benefit payments		(898)
Executive benefit restoration at end of period	**$**	**9,628**
Fair value of plan assets at beginning of period	$	10,298
Benefits paid		(898)
Actual return on plan assets		153
Fair value of plan assets at end of period	**$**	**9,553**
Net liability recognized at end of period	**$**	**75**

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, 2024	
Accumulated other comprehensive loss at beginning of period	$	(1,639)
Amortization of prior service cost into other income		509
Accumulated other comprehensive loss at end of period	**$**	**(1,130)**

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. Our contracts with our Utility Members extend through 2050.

Member electric sales

Revenues from wholesale electric power sales to our Utility Members are primarily from our Class A rate schedule filed with FERC. Our Class A rate schedule for electric power sales to our Utility Members consist of three billing components: an energy rate and two demand rates. Our Class A rate schedule is variable and is approved by our Board and FERC. 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.

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,	
	2024	**2023**	**2024**	**2023**
Non-member electric sales:				
Long-term contracts	$ 29,813	$ 8,996	$ 51,188	$ 21,796
Short-term contracts	8,955	9,490	23,199	38,640
Rate stabilization	16,901	11,064	16,901	22,821
Provision for rate refunds	—	(6)	—	304
Coal sales	1,814	3,315	3,458	4,394
Other	21,730	11,371	40,190	28,150
Total non-member electric sales and other operating revenue	**$ 79,213**	**$ 44,230**	**$ 134,936**	**$ 116,105**

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.

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 $16.9 million of deferred membership withdrawal for the six months ended June 30, 2024 compared to $22.8 million of deferred membership withdrawal for the six months ended June 30, 2023. See Note 2 - Accounting for Rate Regulation.

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. We recognize coal sales revenue in other operating revenue on our consolidated statements of operations.

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 agreement with a third party at our Knutson 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 adopted the normalization method January 1, 2020 pursuant to FERC regulation. Our subsidiaries not subject to FERC regulation continued to use a 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 payables that will be settled or received through future rate revenues.

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, 2024 and an income tax expense of $45 thousand for the comparable period in 2023. We are continuing to evaluate the tax impacts of the contract termination payment received from United Power. 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 2024 when the amount of deferred revenue recognized will be known.

On August 16, 2022, the Inflation Reduction Act of 2022 (the "IRA") was enacted into law. The IRA enacted many provisions intended to mitigate climate change by providing various sources of funding and tax credit incentives for investments designed to reduce greenhouse gas emissions. These provisions do not impact our current consolidated financial statements but could affect future financial statements due to the impact of such investments. These provisions are subject to regulations and other guidance to be released by the U.S. Department of the Treasury, the U.S. Department of Agriculture and other governmental agencies over time. We are monitoring developments and evaluating opportunities to utilize these incentives. In September 2023, we submitted a Letter of Interest to apply for a funding award of low-cost loans and grants through the New Empowering Rural America ("New ERA") Program. In March 2024, we received an Invitation to Proceed from the U.S. Department of Agriculture to complete the New ERA Program Application, and in June 2024, we submitted our Application. The New ERA Program implements the $9.7 billion funded in the IRA.

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 $0.7 million for the three months ended June 30, 2024 and $0.6 million for the comparable period in 2023. Rent expense for all short-term and long-term operating leases was $1.3 million for the six months ended June 30, 2024 and $1.2 million for the comparable period in 2023. 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.

In May 2024, we entered into several land leases in connection with our acquisition of the Dolores Canyon Solar project being developed in southwestern Colorado and commencing construction on such project. The term of those leases is 30 years with two five-year renewal option periods which we are reasonably assured to exercise.

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

	June 30, 2024	December 31, 2023
Operating leases:		
Operating lease right-of-use assets	$ 13,238	$ 9,072
Less: Accumulated amortization	(2,919)	(2,595)
Net operating lease right-of-use assets	**$ 10,319**	**$ 6,477**
Operating lease liabilities - current	$ (471)	$ (371)
Operating lease liabilities - noncurrent	(5,461)	(1,396)
Total operating lease liabilities	**$ (5,932)**	**$ (1,767)**
Finance leases:		
Finance lease right-of-use assets	$ 95	$ —
Less: Accumulated amortization	(7)	—
Net finance lease right-of-use assets	$ 88	$ —
Finance lease liabilities - current	$ (46)	$ —
Finance lease liabilities - noncurrent	(37)	—
Total finance lease liabilities	$ (83)	$ —
Lease Term and Discount Rate:		
Weighted-average remaining lease term (in years)		
Operating leases	32.1	7.0
Finance leases	1.9	0.0
Weighted-average discount rate		
Operating leases	6.91 %	4.68 %
Finance leases	6.99%	—%

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

	Operating Leases		Finance Leases		Total
Year 1	$	703	$	51	$ 754
Year 2		517		38	555
Year 3		531		—	531
Year 4		838		—	838
Year 5		432		—	432
Thereafter		12,401		—	12,401
Total lease payments	**$**	**15,422**	**$**	**89**	**$ 15,511**
Less imputed interest		(9,490)		(6)	(9,496)
Total	**$**	**5,932**	**$**	**83**	**$ 6,015**

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $4.7 million and $1.7 million for the three months ended June 30, 2024 and 2023 and $6.4 million and $3.4 million for the six months ended June 30, 2024 and 2023, respectively, 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 substance, this agreement was determined to be a lease 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, 2024		December 31, 2023	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 9,987	$ 9,553	$ 10,821	$ 10,298

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, 2024		December 31, 2023	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 557	$ 564	$ 576	$ 530

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 $256.0 million as of June 30, 2024 and $83.0 million as of December 31, 2023.

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, 2024		December 31, 2023	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 2,914,553	$ 2,615,600	$ 3,137,534	$ 2,909,301

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, 2024	December 31, 2023
Net electric plant	$ 694,790	$ 703,859
Noncontrolling interest	129,737	134,269
Long-term debt	173,091	206,027
Accrued interest	4,997	5,968

Our consolidated statements of operations include the following Springerville Partnership expenses for the three and six months ended June 30, 2024 and 2023 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Depreciation, amortization and depletion	$ 4,535	$ 4,535	$ 9,069	$ 9,069
Interest	2,852	3,401	5,885	7,068

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, 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. 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 April 29, 2022, both United Power and Northwest Rural Public Power District ("NRPPD") provided us notices to withdraw from membership in us, with a May 1, 2024 withdrawal effective date.

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 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 with the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit Court of

Appeals"), Case No. 24-1081. United Power, Mountain Parks Electric, Inc. ("MPEI"), 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 2, 2024, FERC filed with the DC Circuit Court of Appeals a motion to transfer United Power's petition for review filed in the DC Circuit Court of Appeals to the 10th Circuit Court of Appeals. On May 14, 2024, the DC Circuit Court of Appeals granted a motion to transfer United Power's petition to the 10th Circuit Court of Appeals, Case No. 24-9532.

On May 23, 2024, FERC issued a substantive order on rehearing, which modifies the discussion in, but sustains 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 Case No. 24-9538 with Case Nos. 24-9516 and 24-9532 for purposes of briefing. Briefing is scheduled to begin in October 2024.

On July 2, 2024, United Power, NRPPD, MPEI and LPEA filed with the 10th Circuit Court of Appeals a joint motion to transfer our petition for review to the DC Circuit Court of Appeals. On July 17, 2024, we filed a response opposing this joint motion to transfer. On July 23, 2024, the court denied the joint motion to transfer our petition for review from the 10th Circuit Court of Appeals.

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. On April 12, 2024, we submitted a further revised Rate Schedule 281 as directed by FERC's March 2024 order. On June 28, 2024, we submitted a further revised Rate Schedule 281 as directed by FERC's May 23 Order. FERC has not issued an order on our April 2024 or June 2024 revised Rate Schedule 281 so our January 2024 Rate Schedule 281 is currently on-file with FERC.

On May 1, 2024, United Power withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement with United Power. United Power's contract termination payment amount was $709.4 million. United Power paid us an exit fee in cash of $627.2 million, after a regulatory liabilities credit and United Power relinquishing its right to any patronage capital in us resulting in a discounted patronage capital credit of $82.2 million. Such amounts remain subject to true-up in accordance with Rate Schedule 281 and United Power's Membership Withdrawal Agreement. As provided in the Membership Withdrawal Agreement, United Power's exit fee is also subject to true-up in the event Rate Schedule 281 and the amount paid by United Power are modified pursuant to a subsequent final and non-appealable FERC order, including resolution of the petitions for review filed by us and United Power. 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 if United Power will be required to pay us any additional amounts.

NRPPD did not comply with Rate Schedule 281 on-file with FERC and made no contract termination payment to us. NRPPD's wholesale electric service contract with us remains in effect and NRPPD remains a Class A member of us. NRPPD's April 29, 2022 notice of intent to withdraw is deemed null and void. NRPPD is disputing our position that their wholesale electric service contract with us remains in effect and NRPPD remains a Class A member of us. It is not possible to predict the outcome of the proceedings related to NRPPD's status as a Class A member or its position that it has terminated its wholesale electric service contracts with us and whether we will suffer any liability or loss from the proceedings.

LPEA's La Plata County District Court Complaint. On November 10, 2023, LPEA filed a complaint with the La Plata County District Court, Case No. 2023CV30148, against us. The complaint alleges, among other things, that we have breached our Bylaws and our wholesale electric service contract with LPEA by failing to provide equitable terms and conditions for LPEA to withdraw from us and by violating the implied covenant of good faith and fair dealing. LPEA seeks a declaratory order that we have materially breached our Bylaws and our wholesale electric service contract and that LPEA is relieved from any further obligation to perform under those agreements, or in the alternative, damages from us for such alleged breach. On January 10, 2024, we filed a motion to dismiss stating that LPEA's claims are barred by federal preemption and the statute of limitations. On July 18, 2024, the court denied our motion to dismiss, ruling that the case was not preempted by FERC's jurisdiction and should not be dismissed for violating the statute of limitations. On August 1, 2024, we filed our answer denying all of the allegations in LPEA's complaint and that LPEA is entitled to any relief. It is not possible to predict the outcome of this matter, whether we will incur any liability in connection with this matter, and in the event of liability, if any, the amount or type of damages, equitable relief or other legal relief that could be awarded or granted.

NRPPD Complaint: On March 25, 2024, NRPPD filed a 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 our Amended and Restated Wholesale Power Contract for the Eastern Interconnection with Basin ("Basin Eastern

WPC"). In particular, NRPPD requests 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. NRPPD further seeks refunds from us because Basin has allegedly overcharged us and thus NRPPD for sales of power and energy under the Basin Eastern WPC for Basin’s financial losses caused by Basin’s Urea facility. On May 8, 2024, we and Basin separately filed answers to NRPPD's complaint. Both us and Basin requested FERC to deny NRPPD's complaint. We also requested to the extent FERC determines that NRPPD's withdrawal is permissible under the Basin Eastern WPC that we can be permitted to allocate the withdrawing member its portion of costs related to the Basin Eastern WPC pursuant to our Rate Schedule 281 to prevent the cost of the obligation from shifting to remaining members. On May 28, 2024, NRPPD filed a response to our and Basin's answers and again asserted that its withdrawal from us is permissible under the Basin Eastern WPC and if, prohibited, the Basin Eastern WPC be held not just and reasonable and NRPPD be permitted to withdraw from us. It is not possible to predict the outcome of this matter or whether we will incur any liability or loss in connection with 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 our 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 October 31, 2023, the final briefs were filed in this consolidated proceeding. 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. 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.

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 currently owned entirely by our forty-four Members. We have three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and non-utility members. For our forty-one Class A members, we provide electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members, and therefore all our Utility Members are currently Class A members. We have three Non-Utility Members. Thirty-seven 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 became regulated as a public utility under Part II of the FPA on September 3, 2019 when we admitted a Non-Utility Member, MIECO, Inc. (a non-governmental/non-electric cooperative entity), as a new Member/owner.

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 4,523 MWs, of which approximately 1,566 MWs comes from renewables. In June 2024, the 200 MW Escalante Solar project achieved commercial operation and we began purchasing energy pursuant to a seventeen year power purchase contract.

We sold 8.8 million MWhs for the six months ended June 30, 2024, an increase of 4.3 percent as compared to the six months ended June 30, 2023, of which 87.7 percent was to Utility Members. Total revenue from electric sales was $628.5 million for the six months ended June 30, 2024 of which 88.2 percent was from Utility Member sales. Our results for the six months ended June 30, 2024 were primarily impacted by higher non-member electric sales and lower natural gas prices.

- Utility Member electric sales decreased $12.3 million, or 2.2 percent, primarily due to a decrease of 95,250 MWhs sold, or 1.2 percent, for the six months ended June 30, 2024 compared to the same period in 2023. The impact of United Power's withdrawal on May 1, 2024 was offset by increased sales to our remaining Utility Members sales due to load growth and other factors.

- Non-member electric sales increased $14.0 million, or 23.1 percent, primarily due to higher long-term sales (in MWhs), offset by lower average prices.

- Fuel expense decreased $18.2 million, or 14.4 percent, primarily due to a decrease in generation at both our coal and gas-fired facilities, as well as lower market prices.

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, at least 95 percent of its electric power requirements from us. Our wholesale electric service contracts with our 41 Utility Members extend through 2050. We had a wholesale electric service contract with United Power that extended through 2050 (which constituted approximately 13.7 percent of our revenue from Utility Member sales for the six months ended June 30, 2024). United Power withdrew from membership in us on May 1, 2024 and its wholesale electric service contract was terminated. Each Utility Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Utility Member. As of June 30, 2024, 21 Utility Members have enrolled in this program with capacity totaling approximately 94 MWs of which 88 MWs are in operation.

We have presented to our Utility Members and received feedback on alternatives for an increased amount of self-supply in addition to the 5 percent self-supply provision of our wholesale electric services contracts. The alternative that emerged through our collaboration with our Utility Members is known as the Bring Your Own Resource Program, which is designed to provide our Utility Members with the flexibility to build, own or contract for power supply projects. Under the Bring Your Own Resource Program, Utility Members interested in participating in the 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. In June 2024, we filed with FERC a tariff describing the parameters of the Bring Your Own Resource Program. In August 2024, FERC accepted our tariff and the Bring Your Own Resource Program cycle for the first proposal, evaluation and implementation steps is expected to begin in the third quarter of 2024 and conclude in the first quarter of 2025. For a Utility Member to participate in the Bring Your Own Resource Program, a Utility Member will enter into an agreement with us for us to purchase the output of the Bring Your Own Resource Program project and that output will be deemed to serve the Utility Member's load.

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. 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. In January 2024, we filed a revised Rate Schedule 281 with FERC with the contract termination methodology based upon FERC's order. The revised Rate Schedule 281 based upon FERC's adopted balance sheet approach uses our FERC financials and distinguishes between Utility Members served on the Western and Eastern Interconnection. In March 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 2024, we submitted a further revised Rate Schedule 281 as directed by FERC's March 2024 order. In June 2024, we submitted a further revised Rate Schedule 281 as directed by FERC's May 2024 order on rehearing. FERC has not issued an order on our April 2024 or June 2024 revised Rate Schedule 281 so our January 2024 Rate Schedule 281 is currently on-file with FERC. For further information on the methodology 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, 2023. See also Note 18 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

On April 29, 2022, both United Power and NRPPD provided us notices to withdraw from membership in us, with a May 1, 2024 withdrawal effective date. In January 2023, MPEI provided us a notice to withdraw from membership in us, with a February 1, 2025 withdrawal effective date. In March 2024, LPEA provided us a notice to withdraw from membership in us, with an April 1, 2026 withdrawal effective date.

On May 1, 2024, United Power withdrew from membership in us and terminated its wholesale electric service contract with us pursuant to Rate Schedule 281 on-file with FERC and a Membership Withdrawal Agreement with United Power. United Power's contract termination payment amount was $709.4 million. United Power paid us an exit fee in cash of $627.2 million, after a regulatory liabilities credit and United Power relinquishing its right to any patronage capital in us resulting in a discounted patronage capital credit of $82.2 million. Such amounts remain subject to true up in accordance with Rate Schedule 281 and United Power's Membership Withdrawal Agreement. Our Board deferred as a regulatory liability $530.1 million of United Power's $709.4 million contract termination payment amount. The remaining $179.3 million is related to a transmission credit for the portion of transmission debt allocated to United Power and required to be deferred pursuant to FERC's December 2023 order and Rate Schedule 281. On May 8, 2024, we sold to United Power certain assets for $75 million that were primarily used to serve United Power's load after our receipt of approval from FERC on May 1, 2024. On August 1, 2024, we also sold to United Power additional assets for $1.7 million that were used primarily for transmission service for United Power's load.

NRPPD did not comply with the Rate Schedule 281 on-file with FERC and made no contract termination payment to us. NRPPD's wholesale electric service contract with us remains in effect and NRPPD remains a Class A member of us. NRPPD's April 29, 2022 notice of intent to withdraw is deemed null and void. Contrary to FERC's March 2024 order on our revised Rate Schedule 281 compliance filing, NRPPD has asserted there is no FERC-accepted Rate Schedule 281 on file with FERC and no contract termination payment is payable by NRPPD. Although NRPPD is disputing our position that their wholesale electric service contract with us remains in effect and NRPPD remains a Class A member of us, NRPPD has paid or agreed to pay us for the electric power and energy we provided to NRPPD for May and June 2024.

MPEI's and LPEA's estimated contract termination payments based upon our April 2024 revised Rate Schedule 281 are $77.9 million and $209.6 million, respectively, prior to any reduction for discounted patronage capital or regulatory liabilities credit, if applicable. These estimated contract termination payments do not include their respective pro rata share of our power purchase obligations in the Western Interconnection. MPEI and LPEA comprised 8.1 percent of our Utility Member revenue and 6.5 percent of our operating revenue for the six months ended June 30, 2024.

The contract termination payments for United Power, MPEI, and LPEA are 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.

Although there is no certainty that MPEI and LPEA will pay their respective contract termination payment required upon withdrawal and withdraw as they have asserted, if these Utility Members pay and withdraw, it will reduce our Utility Members' electric sales revenue and the amount of energy sold to our Utility Members. We expect the receipt of the contract termination payments from United Power, MPEI, and LPEA to assist in mitigating the impacts of decreased Utility Members electric sales revenue. We expect to defer some or all of the contract termination payments received as a regulatory liability and recognize as revenue in future period or periods to offset the revenue otherwise recoverable from Utility Members.

In addition, as part of mitigating the impacts, we expect our non-member electric sales revenue and the amount of energy sold to non-members to increase significantly. In anticipation of Utility Member withdrawals, we have entered into with third parties multiple power sales contracts for up to 310 MWs and a tolling agreement for our two 70 MW units at the Knutson Generating Station for the sale of capacity and energy, with certain transactions that started on May 1, 2024. Our Phase I 2023 ERP also assumed United Power and MPEI will withdraw resulting in a decreased need for additional resources and costs as we transition to a cleaner energy portfolio and reduce our greenhouse gas emissions. However, there is no certainty that our mitigation steps or the contract termination payments will mitigate the full amount of the loss of Utility Member electric sales revenue. 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, 2023.

In November 2023, LPEA filed a complaint for declaratory judgement and damages against us alleging, among other things, that we have breached our Bylaws and our wholesale electric service contract with LPEA. In January 2024, we filed a motion to dismiss stating that LPEA's claims are barred by federal preemption and the statute of limitations. In July 2024, the court denied our motion to dismiss. In August 2024, we filed an answer denying all of LPEA's claims. See Note 18 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

Responsible Energy Plan and Colorado Electric Resource Plan and New Era Program

Responsible Energy Plan

In January 2020, we released our energy transition plan known as our Responsible Energy Plan. With our Responsible Energy Plan, we are implementing a clean energy transition while being responsible to our employees, Members, communities, and environment. The plan was developed with input from our Board, our Utility Members and external stakeholders. Our plan is dynamic and will change as Utility Members' needs change, new technologies become available and market conditions evolve. We and our Utility Members have made great strides implementing the plan. Some of the highlights of the Responsible Energy Plan include:

- eliminating all emissions from our coal-fired generating facilities in Colorado and New Mexico by 2030.
- by 2025, 50 percent of the electricity our Utility Members use is expected to come from clean energy.
- more local renewables for Utility Members through contract flexibility.
- promoting participation in a regional transmission organization.
- expanding electric vehicle infrastructure and beneficial electrification.

For further information regarding our Responsible Energy Plan, see "Item 1 – BUSINESS — MEMBERS – Responsible Energy Plan" in our annual report on Form 10-K for the year ended December 31, 2023.

Colorado Electric Resource Plan

In December 2023, we filed our Phase I 2023 ERP with the COPUC, which contained our preferred plan and submitted a filing in April 2024 affirming the preferred plan. Our preferred plan is the IRA scenario, which brings online 1,540 MWs of new resources during the resource acquisition period of 2026-2031, if we are awarded federal funding to support generation additions and provide stranded asset relief under the New ERA Program funding opportunity. Our preferred plan enables us to utilize direct pay of federal tax benefits for renewable and storage resources by increasing our owned resources. Our preferred plan retires 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 September 15, 2031. These shifts in our generation portfolio included in our preferred plan over the coming years are expected to result in an 89 percent greenhouse gas emissions reduction for our wholesale electricity sales in Colorado in 2030, with respect to a verified 2005 baseline. This emissions reduction exceeds the emissions reduction target of 80 percent in 2030 required by Colorado law.

In June 2024, we filed an unopposed executed comprehensive settlement agreement for our Phase I 2023 ERP with the COPUC supporting its approval subject to the terms of the settlement, including the above referenced retirements of our generating facilities and retirement dates. The settlement resolves all issues raised by intervening parties for our Phase I 2023 ERP and provides for updates related to the scope of Phase II procurement, bid evaluation and portfolio modeling, and adds a demand response target for our Colorado peak load in 2030 of 5.5 percent. In the Phase II resource procurement process, we will issue three requests for proposals seeking bids for new dispatchable, renewable, and storage resources for the resource acquisition period of 2026-2031. For our dispatchable request for proposal, for any bid for a new natural gas-fired generating facility to be owned by us it must be sited in Moffat County, Colorado. Other gas facility and geothermal bids under a tolling or power purchase arrangement have more geographic flexibility. The settlement agreement provides for us to provide community assistance for northwest Colorado, which is the location of Craig Generating Station. Community assistance includes $22 million in direct total benefit to the northwest Colorado community between 2026 and 2029, with other potential investments providing $48 million in additional benefit to such community between 2028 and 2038. The settlement is subject to COPUC approval. For further information regarding our Phase I 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, 2023.

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. The details of the portfolio proposed in our Letter of Interest are a result of resource and financial modeling performed in connection with our preferred IRA scenario as part of our Phase I 2023 ERP. Our Letter of Interest expands and further supports the implementation of our Responsible Energy Plan. In March 2024, we received an Invitation to Proceed from the U.S. Department of Agriculture to complete the New ERA Program Application, and in June 2024, we submitted our Application. The New ERA Program implements the $9.7 billion funded in the Inflation Reduction Act of 2022.

Solar Project Acquisitions

In March 2024, we executed an asset purchase agreement to purchase the 145 MW Axial Basin Solar project being developed in northwestern Colorado located near the Colowyo Mine. Concurrent with execution of the purchase agreement, we also executed an engineering, procurement and construction contract with an affiliate of the developer of the project. In April 2024, we closed on the acquisition of Axial Basin Solar project, terminated the power purchase contract for this project, and issued a notice to proceed with construction to the contractor. Construction of the Axial Basin Solar project at the site has commenced with access road construction and trenching underway and all solar modules have been ordered, shipped and placed in storage.

In April 2024, we executed an asset purchase agreement to purchase the 110 MW Dolores Canyon Solar project being developed in southwestern Colorado. Concurrent with execution of the purchase agreement, we also executed an engineering, procurement and construction contract with an affiliate of the developer of the project. In May 2024, we closed on the acquisition of Dolores Canyon Solar project, terminated the power purchase contract for this project, and issued a notice to proceed with construction to the contractor. Construction of the Dolores Canyon Solar project at the site has commenced and all solar modules have been ordered, shipped and placed in storage.

Both projects are expected to achieve commercial operation in the second half of 2025 . We also expect to utilize direct pay of federal tax benefits as provided in the Inflation Reduction Act of 2022 for both projects.

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, 2024, 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, 2023.

Factors Affecting Results

Master Indenture

As of June 30, 2024, we had approximately $2.7 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.

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, 2024, we have retired approximately $605.8 million of patronage capital to our Members, including the $82.2 million we retired and United Power relinquished its right to as part of United Power's withdrawal from membership in us.

Pursuant to our Board Policy for Financial Goals and Capital Credits, we have historically set rates to achieve a DSR and ECR in excess of the requirements under our Master Indenture in order to mitigate the risk of potential negative variances between budgeted margins and actual margins. Our Board Policy for Financial Goals and Capital Credits, approved in 2023 in connection with our Board's approval of a revised Class A rate schedule that uses a formula rate, 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 approved revised rates to our Utility Members, which was filed with FERC in May 2024 and accepted by FERC in July 2024, with an August 1, 2024 effective date, subject to refund, to achieve a DSR and ECR in excess of the requirements under our Master Indenture, including a DSR of approximately 1.17 largely driven by a minimum net margin attributable to us of at least $20 million for 2024. Based on our revised 2024 budget filed with FERC in May 2024 as part of our revised Class A rate schedule, we at that time forecasted the recognition of $127 million deferred membership withdrawal during 2024.

Rates and Regulation

On September 3, 2019, we became FERC jurisdictional for our Utility Members' rates, transmission service, and our market based rates. In December 2019, we filed with FERC our tariff filings, including our stated rate cost of service filing, market-based rate authorization, and transmission OATT. In March 2020, FERC issued orders generally accepting our tariff filings, subject to refund for sales after March 26, 2020. On August 2, 2021, FERC approved our settlement agreement related to our Utility Members' stated rate that provides for us to implement a two-stage, graduated reduction in the charges making up our A-40 rate of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from then current rates) on March 1, 2022 until August 1, 2024, which is the date a new Class A wholesale rate schedule went into effect, subject to refund. For further information, see "Item 1 – BUSINESS — RATE REGULATION" in our annual report on Form 10-K for the year ended December 31, 2023.

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

Revenues from 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) for electric power sales to our Utility Members consist of three billing components: an energy rate and two demand rates. Utility Members' rates for energy and demand are 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 rate was billed based upon a price per kWh of physical energy delivered and the two demand rates (a generation demand and a transmission/delivery demand) were both billed based on the Utility Member’s highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays.

As part of the settlement agreement for our Utility Members' stated rate, we agreed to file a new Class A rate schedule with FERC before September 1, 2023. We established a rate design committee to oversee the development of the new rate. In June 2023, we filed with FERC the new Class A rate schedule (A-41) that uses a formula rate and requested for the new rate to take effect on January 1, 2024 and included a 6.4 percent rate increase. In March 2024, FERC rejected our Class A formula rate resulting in our Class A rate schedule (A-40) remaining in effect. FERC's rejection related to unbundling of rate components for ancillary services on our bills to our Utility Members and allocation of costs across the Eastern and Western Interconnection. FERC's rejection was not related to our ability to recover costs, including our rate increase.

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 filing includes a 6.4 percent increase in our average wholesale rate. The wholesale rate maintains our postage stamp rate, with the same rate components for all its 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. The filing addresses several non-cost recovery issues raised by FERC in response to our previous wholesale rate filing, and further unbundles rate components for ancillary services and provides support for rolled-in rate treatment, including across the Eastern and Western interconnections. 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 and confirmed our accounting treatment, including amortization, and creation of regulatory assets for Escalante Generating Station, Rifle Generating Station, Craig Generating Station Units 2 and 3, and the New Horizon Mine environmental obligation. However, FERC did not currently authorize us to recover the regulatory assets that represent "acquisition costs/goodwill" for J.M. Shafer Generating Station and Colowyo Coal, with an aggregate balance of $68.9 million as of June 30, 2024. These costs were on our books prior to us becoming subject to FERC's jurisdiction. FERC stated in its order accepting our A-41 rate schedule that we did not request express authorization to recover acquisition costs including goodwill in our rates. We are evaluating next steps regarding these costs.

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. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit). Our subsidiaries are not subject to FERC regulation and continue to use a 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.

Impacts of Supply Chain and Inflation

Our ability to meet our Utility Members' electric power requirements and complete our capital projects is 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. Inflation has contributed to higher prices for materials and equipment. We continue to monitor potential impacts to our operations and estimated capital expenditures and timing of projects related to inflationary pressures and supply chain disruptions.

Three Months Ended June 30, 2024 Compared to Three Months Ended June 30, 2023

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, 2024 and 2023 (dollars in thousands):

	Three Months Ended June 30,		Period-to-period Change	
	2024	2023	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 258,286	$ 274,225	$ (15,939)	(5.8)%
Non-member electric sales	38,768	18,486	20,282	109.7 %
Rate stabilization	16,901	11,064	5,837	52.8 %
Provision for rate refunds	—	(6)	6	(100.0)%
Other	23,544	14,686	8,858	60.3 %
Total operating revenues	**$ 337,499**	**$ 318,455**	**$ 19,044**	6.0 %
Energy sales (in MWh):				
Utility Member electric sales	3,528,944	3,700,945	(172,001)	(4.6)%
Non-member electric sales	628,456	209,658	418,798	199.8 %
	4,157,400	**3,910,603**	**246,797**	6.3 %

- Excluding United Power, Member load growth increased 326,930 MWh, or 11.1 percent, during the three months ended June 30, 2024 compared to the same period in 2023. The United Power membership withdrawal on May 1, 2024 resulted in a decrease of 498,931 MWh sold to United Power for the three months ended June 30, 2024 compared to the same period in 2023. The impact of the United Power membership withdrawal 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 higher long-term and short-term market sales. Long-term sales increased 338,725 MWhs to 356,176 MWhs for the three months ended June 30, 2024 compared to 17,451 MWhs for the same period in 2023. Short-term market sales increased 81,903 MWh, or 192.3 percent, to 124,494 MWh for the three months ended June 30, 2024 compared to 42,591 MWh for the same period in 2023. The ability to sell excess power pursuant to long-term arrangements and the short-term market after United Power's membership withdrawal contributed significantly to the increase in non-member electric sales.
- We recognized $16.9 million of previously deferred membership withdrawal during the three months ended June 30, 2024 compared to $11.1 million during the same period in 2023 as part of our rate stabilization measures. We expect to recognize additional previously deferred membership withdrawal during the remainder of 2024.
- Other operating revenue increased primarily due to the sale of excess intangible assets and an increase in lease revenue related to a tolling agreement for our two 70 MW units at the Knutson Generating Station for all capacity and energy through the operation of both units that started on May 1, 2024.

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, 2024 and 2023 (dollars in thousands):

	Three Months Ended June 30,		Period-to-period Change	
	2024	2023	Amount	Percent
Operating expenses				
Purchased power	$ 98,840	$ 95,281	$ 3,559	3.7 %
Fuel	32,208	44,773	(12,565)	(28.1)%
Production	47,057	54,423	(7,366)	(13.5)%
Transmission	44,964	46,280	(1,316)	(2.8)%
General and administrative	23,830	23,577	253	1.1 %
Depreciation, amortization and depletion	44,152	42,690	1,462	3.4 %
Coal mining	1,027	4,130	(3,103)	(75.1)%
Other	3,250	2,417	833	34.5 %
Total operating expenses	**$ 295,328**	**$ 313,571**	**$ (18,243)**	(5.8)%

- Fuel expense decreased primarily due to a lower average rate for natural gas of 31.3 percent, a lower average rate for coal of 22.2 percent, a decrease of 54,163 MWhs in generation by our natural gas-fired generating facilities, and a decrease of 94,300 MWhs in generation by our coal-fired generating facilities during the three months ended June 30, 2024 compared to the same period in 2023.

Six Months Ended June 30, 2024 Compared to Six Months Ended June 30, 2023

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, 2024 and 2023 (dollars in thousands):

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023	Period-to-period Change Amount	Period-to-period Change Percent
Operating revenues				
Utility Member electric sales	$ 554,112	$ 566,401	$ (12,289)	(2.2)%
Non-member electric sales	74,387	60,436	13,951	23.1 %
Rate stabilization	16,901	22,821	(5,920)	(25.9)%
Provision for rate refunds	—	304	(304)	(100.0)%
Other	43,648	32,544	11,104	34.1 %
Total operating revenues	**689,048**	**682,506**	**$ 6,542**	1.0 %
Energy sales (in MWh):				
Utility Member electric sales	7,701,135	7,796,387	(95,252)	(1.2)%
Non-member electric sales	1,081,229	620,652	460,577	74.2 %
	8,782,364	**8,417,039**	**365,325**	4.3 %

- Excluding United Power, Member load growth increased 372,412 MWh, or 6.0 percent, for the six months ended June 30, 2024 compared to the same period in 2023. The United Power membership withdrawal on May 1, 2024 resulted in a decrease of 467,664 MWh sold to United Power for the six months ended June 30, 2024 compared to the same period in 2023. The impact of the United Power membership withdrawal 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 and short-term market sales. Long-term sales increased 475,445 MWhs, or 477.1 percent, to 575,106 MWhs for the six months ended June 30, 2024 compared to 99,661 MWhs for the same period in 2023. Short-term market sales increased 116,682 MWh, or 136.9 percent to 201,939 MWhs for the six months ended June 30, 2024 compared to 85,257 MWhs for the same period in 2023. The ability to sell excess power pursuant to long-term arrangements and the short-term market after United Power's membership withdrawal contributed significantly to the increase in non-member electric sales.
- We recognized $16.9 million of deferred membership withdrawal during the six months ended June 30, 2024 compared to $22.8 million of deferred membership withdrawal during the same period in 2023 as part of our rate stabilization measures. We expect to recognize additional previously deferred membership withdrawal during the remainder of 2024.
- Other operating revenue increased primarily due to the sale of intangible assets and an increase in lease revenue related to a tolling agreement for our two 70 MW units at the Knutson Generating Station for all capacity and energy through the operation of both units that started on May 1, 2024.

Operating Expenses

The following is a summary of the components of our operating expenses for the six months ended June 30, 2024 and 2023 (dollars in thousands):

	Six Months Ended June 30,		Period-to-period Change	
	2024	2023	Amount	Percent
Operating expenses				
Purchased power	191,910	196,106	$ (4,196)	(2.1)%
Fuel	108,548	126,703	(18,155)	(14.3)%
Production	89,183	97,975	(8,792)	(9.0)%
Transmission	92,522	95,308	(2,786)	(2.9)%
General and administrative	45,563	42,075	3,488	8.3 %
Depreciation, amortization and depletion	88,776	85,071	3,705	4.4 %
Coal mining	2,105	5,769	(3,664)	(63.5)%
Other	6,200	8,712	(2,512)	(28.8)%
Total operating expenses	**$ 624,807**	**$ 657,719**	**$ (32,912)**	(5.0)%

- Fuel expense decreased due to a decrease of 151,328 MWhs in generation by our natural gas-fired generating facilities, a decrease of 398,663 MWhs in generation by our coal-fired generating facilities, a lower average rate for coal of 7.6 percent, and lower average rate for natural gas of 6.4 percent for the six months ended June 30, 2024 compared to the same period in 2023.
- Production expense decreased due to lower maintenance expenses of $8.3 million for the six months ended June 30, 2024 compared to the same period in 2023.

Financial Condition as of June 30, 2024 Compared to December 31, 2023

The principal changes in our financial condition from December 31, 2023 to June 30, 2024 were due to increases and decreases in the following:

Assets

- Construction work in progress increased $92.3 million, or 56.3 percent, to $256.3 million as of June 30, 2024 compared to $164.0 million as of December 31, 2023. The increase was primarily due to capital expenditures of $194.7 million, primarily for the Axial Basin Solar project, the Dolores Canyon Solar project, various transmission and generation projects and migrating and upgrading software systems to hosted solutions, partially offset by transfers to electric plant in service for completed projects of $102.4 million.
- Restricted cash and investments increased $168.9 million to $172.9 million as of June 30, 2024 compared to $4.0 million as of December 31, 2023. The increase was primarily due a portion of United Power's contract termination payment that was restricted by contract.
- Deposits and advances increased $41.6 million to $79.1 million as of June 30, 2024 compared to $37.5 million as of December 31, 2023. The increase was primarily due to migrating and upgrading software solutions to hosted solutions and prepayments of annual insurance, memberships and licenses. These prepayments are being amortized to expense over the term of the related insurance, membership or license period.

Liabilities

- Short-term borrowings decreased $68.2 million to $116.1 million as of June 30, 2024 compared to $184.3 million as of December 31, 2023. The majority of the decrease was due to operating cash flow.
- Regulatory liabilities increased $691.5 million to $693.8 million as of June 30, 2024 compared to $2.3 million as of December 31, 2023. The increase was primarily due to United Power's $709.4 million contract termination payment amount arising from their withdrawal from membership in us and the termination of their wholesale electric service contract with us. Our Board deferred as a regulatory liability $530.1 million of United Power's contract termination payment amount. The remaining $179.3 million is related to a transmission credit for the portion of transmission debt allocated to United Power and required to be deferred pursuant to FERC's December 2023 order and Rate Schedule 281. Regulatory liabilities was also impacted by the recognition of deferred membership withdrawal of $16.9 million during the six month period ended June 30, 2024 as part of our rate stabilization measures.

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, 2024, we had $110.5 million in cash and cash equivalents. Our committed credit arrangement as of June 30, 2024 is as follows (dollars in thousands):

	Authorized Amount		Available June 30, 2024	
2022 Revolving Credit Agreement	$ 520,000	(1)	$ 404,000	(2)

(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, 2024 was $116 million which was dedicated to support outstanding commercial paper.

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, $75 million of the letter of credit sublimit, and $384 million of the commercial paper back-up sublimit remained available as of June 30, 2024.

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, 2024) 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, 2024) 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 contains 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 facility.

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, 2024, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of June 30, 2024, we had $116 million commercial paper outstanding and $384 million available on the commercial paper back-up sublimit. See Note 8 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

On May 8, 2024, we used a portion of United Power's contract termination payment proceeds to payoff the $150 million balance on our 2023 multiple advance rate term loan agreement with CoBank, as administrative agent.

Our First Mortgage Bonds, Series 2014E-1 with $128 million outstanding mature on November 1, 2024. We plan to pay the balance off in full at maturity with restricted cash.

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, 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, 2024 Compared to Six Months Ended June 30, 2023

Operating activities. Net cash provided by operating activities was $743.6 million for the six months ended June 30, 2024 compared to $6.9 million for the same period in 2023, an increase in net cash provided by operating activities of $736.7 million. The increase in net cash provided by operating activities was primarily impacted by United Power's contract termination payment of $709.4 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 and prepayments of annual insurance.

Investing activities. Net cash used in investing activities was $177.3 million for the six months ended June 30, 2024 compared to $80.5 million for the same period in 2023, an increase in net cash used in investing activities of $96.8 million. The increase in net cash used in investing activities was impacted by additional investments in utility plant and timing of payments we made to operating agents of jointly owned facilities to fund our share of costs to be incurred under each project. Additionally, on May 8, 2024, we sold to United Power certain assets for $75 million that were primarily used to serve United Power's load.

Financing activities. Net cash used in financing activities was $392.8 million for the six months ended June 30, 2024 compared to net cash provided by financing activities of $99.7 million for the same period in 2023, a decrease in net cash provided by financing activities of $492.5 million. The decrease in net cash provided by financing activities was primarily due using some of United Power's contract termination payment to payoff the 2023 multiple advance rate term loan and also paying down short-term borrowings. Additionally, financing activities was impacted by a patronage capital retirement of $82.2 million resulting from United Power's withdrawal, with the amount of the discounted patronage capital credit applied to United Power's contract termination payment.

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. After taking into account our our preferred IRA scenario as part of our Phase I 2023 ERP, in the years 2024 through 2028, we forecast that we may invest approximately $2.60 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 Responsible Energy Plan and our Phase I 2023 ERP, receipt of New ERA Program funding and other federal programs, Utility Member load growth or Utility Member withdraws, Bring Your Own Resource Program, availability of necessary permits, regulatory changes, environmental requirements, construction delays and costs, supply chain issues, inflation, 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.

Changing Environmental Regulations

We are subject to various federal, state and local laws, rules and regulations with regard to air quality, including greenhouse gases, water quality, and other environmental matters. These environmental laws, rules and regulations are complex and change frequently. Following are updates on recent developments that may impact us:

Air Quality

Mercury and other Hazardous Air Pollutants. In May 2024, the EPA published final revisions to the National Emission Standards for Hazardous Air Pollutants for coal- and oil-fired electric utility steam generating units pursuant to EPA's risk and technology review as required by Section 112 of the Clean Air Act. The EPA finalized a more stringent emission limit for particulate matter, as a surrogate for non-mercury metals, and requirements for installations of particulate matter continuous emissions monitoring systems. We are assessing options related to these requirements. The revisions are subject to litigation and outstanding motions to stay.

Greenhouse Gas Regulation. In May 2024, the EPA published a final rule regarding emission guidelines for carbon dioxide from certain existing electric generating units under Section 111(d) of the Clean Air Act and certain new electric generating units under Section 111(b) of the Clean Air Act. EPA finalized a matrix of emission requirements that depend on a given unit's fuel type, generating capacity, capacity factor, and years of continued operation. Due to applicability thresholds and previously announced retirement dates of our generating facilities, this particular rule does not, or likely will not, affect most of our generating facilities. However, if not overturned, the rule will drive important decision-making about future operation of and investment in Laramie River Generating Station. The regulation is subject to litigation and outstanding motions to stay.

Other Environmental Matters

Coal Ash Regulation. In May 2024, the 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.

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, 2023.

Rating Triggers

Our current senior secured ratings are “Baa1 (stable outlook)” by Moody’s, “BBB (stable outlook)” by S&P, and “BBB+ (negative 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. 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, 2023.

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 were no changes that occurred during the second quarter ended June 30, 2024 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. In the third quarter of 2024 due to migrating and upgrading software solutions to hosted solutions, we expect changes to 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
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 Todd E. Telesz (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 Todd E. Telesz (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, 2024	By:	/s/ Duane Highley
		Duane Highley
		Chief Executive Officer
Date: August 8, 2024		/s/ Todd E. Telesz
		Todd E. Telesz
		Senior Vice President/Chief Financial Officer (Principal Financial Officer)