UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2023
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)

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

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act. ☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☒ Yes ☐ No

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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262 (b)) by the registered accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant’s executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant: **NONE.**

Indicate the number of shares outstanding of each of the registrant’s classes of common stock. **The registrant is a membership corporation and has no authorized or outstanding equity securities.**

Documents incorporated by reference: **NONE.**

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

Index to 2023 Annual Report on Form 10-K

GLOSSARY

The following abbreviations and acronyms used in this annual report on Form 10-K 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, as amended
AQCC	Colorado Air Quality Control Commission
Basin	Basin Electric Power Cooperative
Board	Board of Directors
CAISO	California Independent System Operator
CERCLA, or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFC	National Rural Utilities Cooperative Finance Corporation
Clean Water Act	Federal Water Pollution Control Act, as amended
CO_2	carbon dioxide
CoBank	CoBank, ACB
Colowyo Coal	Colowyo Coal Company L.P., a subsidiary of ours
COPUC	Colorado Public Utilities Commission
Corps	U.S. Army Corps of Engineers
Craig Station	Craig Generating Station
D.C. Circuit Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DM/NFR	Denver Metropolitan/North Front Range
DSR	Debt Service Ratio (as defined in our Master Indenture)
ECR	Equity to Capitalization Ratio (as defined in our Master Indenture)
Elk Ridge	Elk Ridge Mining and Reclamation, LLC, a subsidiary of ours
EMS	Environmental Management System
EPA	Environmental Protection Agency
ESA	Endangered Species Act
Escalante Station	Escalante Generating Station
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
IRS	Internal Revenue Service
kWh	kilowatt hour
LIBOR	London Interbank Offered Rate
LPEA	La Plata Electric Association, Inc.
MACT	maximum achievable control technology
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
Moody’s	Moody’s Investors Services, Inc.
MPEI	Mountain Parks Electric, Inc.
MRO	Midwestern Reliability Organization
MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standard

NERC	North American Electric Reliability Corporation
New ERA Program	U.S. Department of Agriculture's Empowering Rural America Program
Non-Utility Members	our non-utility members
NO_X	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NRECA	National Rural Electric Cooperative Association
NRPPD	Northwest Rural Public Power District
OATT	Open Access Transmission Tariff
PCB	polychlorinated biphenyl
PFAS	per- and polyfluoroalkyl substances
Phase I 2023 ERP	Phase I of our 2023 Electric Resource Plan filed with the COPUC
PNM	Public Service Company of New Mexico
ppb	parts per billion
PSCO	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act of 1978, as amended
RES	Renewable Energy Standard
RPS	Renewable Portfolio Standard
RS Plan	National Rural Electric Cooperative Association Retirement Security Plan
S&P	S & P Global Ratings
Salt River Project	Salt River Project Agricultural Improvement and Power District
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	sulfur dioxide
SPP	Southwest Power Pool, Inc.
Springerville Partnership	Springerville Unit 3 Partnership LP, a subsidiary of ours
Springerville Unit 3	Springerville Generating Station Unit 3
TEP	Tucson Electric Power Company
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.
USFWS	U.S. Fish and Wildlife Service
Utility Members	our electric distribution member systems, consisting of both Class A members and Class B members
WACM	Western Area Colorado Missouri
WAPA	Western Area Power Administration (a power marketing agency of the U.S. Department of Energy)
WECC	Western Electricity Coordinating Council
WOTUS	Waters of the United States
Yampa Project	Craig Station Units 1 and 2 and related common facilities

FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains "forward–looking statements." All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as the timing of various regulatory and other actions, future capital expenditures, future use of deferred revenue, business strategy, member withdrawals, 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," "is expected to," "planned," "will continue," "is anticipated," "estimated," "forecasted," "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

ITEM 1. BUSINESS

OVERVIEW

Our Business

Tri–State Generation and Transmission Association, Inc. is a taxable wholesale electric power generation and transmission cooperative operating on a not–for–profit basis. We were incorporated under the laws of the State of Colorado in 1952 as a cooperative corporation. We were formed by our Utility Members for the purpose of providing wholesale power and transmission services to our Utility Members for their resale of the power to their retail consumers. Our 42 Utility Members serve large portions of Colorado, Nebraska, New Mexico and Wyoming.

We are owned entirely by our 45 Members. Thirty-eight of our Members are not-for-profit, electric distribution cooperative associations. Four Members are public power districts, which are political subdivisions of the State of Nebraska. We also have three Non-Utility Members. The retail service territories of our Utility Members cover approximately 200,000 square miles and their customers include suburban and rural residences, farms and ranches, and large and small businesses and industries. Our Utility Members serve approximately 628,000 retail electric meters. Our Utility Members are the sole state-certified providers of electric service to retail (residential and business) customers within their designated service territories.

Our principal executive offices are located at 1100 West 116th Avenue, Westminster, Colorado 80234. Our telephone number is (303) 452-6111. Our website is www.tristate.coop. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available on our website as soon as reasonably practicable after the material is filed with the SEC. Information contained on our website is not incorporated by reference into and should not be considered to be part of this annual report.

Cooperative Structure

A cooperative is a business entity owned by its members. As organizations acting on a not-for-profit basis, cooperatives provide or purchase property, products or services to their members on a cost-effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Cooperatives generally establish rates to recover their costs and to collect a portion of revenues in excess of expenses, which constitute margins. Margins not yet distributed to members in cash constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of directors deems it appropriate to do so. The timing and amount of any actual return of capital to the members depends on the financial goals of the cooperative, current and projected capital expenditures, and the cooperative's loan and security agreements.

Electric distribution cooperatives form generation and transmission cooperatives, such as us, to acquire power supply resources, typically through the construction of facilities or the development of other power purchase arrangements, at a lower cost than if they were acquiring those resources alone. Electric cooperatives usually have no equity securities or stock.

FERC Jurisdictional

On September 3, 2019, we became regulated as a public utility under Part II of the FPA when we admitted a Non-Utility Member, MIECO, Inc. (a non-governmental/non-electric cooperative entity), as a new Member/owner.

In December 2019, we filed a set of tariff filings, including our stated rate cost of service to our Utility Members, our wholesale electric service contracts, our Bylaws, certain Board policies, market-based rate authorization, and our transmission OATT. In March 2020, FERC issued orders generally accepting our tariff filings, subject to refund for sales after March 26, 2020, and recognized that we became FERC jurisdictional on September 3, 2019. With the exception of four reserved issues, in August 2021, FERC approved a settlement agreement related to our Utility Member rates, including our stated rate cost of service to our Utility Members, our wholesale electric service contracts, our Bylaws, and certain Board policies. In August 2023, FERC issued an order on those four reserved issues. See " — RATE REGULATION."

In September 2021, we filed as a rate schedule with FERC our modified contract termination payment methodology associated with a Utility Member terminating its wholesale electric service contract with us. FERC accepted our modified contract termination payment methodology, subject to refund. FERC set the matter for hearing and instituted a FPA section 206 proceeding to determine the justness and reasonableness of our modified contract termination payment methodology. A hearing on our modified contract termination payment methodology occurred in May 2022, and in September 2022, the administrative law judge issued an initial decision. Exceptions to the initial decision were filed by various parties, including us. In December 2023, FERC issued an order on the initial decision and adopted a further modified balance sheet approach for the contract termination payment methodology. In January 2024, we filed a compliance filing with a revised rate schedule with FERC with the contract termination methodology based upon FERC's order. We have received notices from three of our Utility Members of their intent to withdraw from membership in us and terminate their respective wholesale electric service contract. United Power and NRPPD provided us notices in April 2022, with a May 1, 2024 withdrawal effective date. MPEI provided us a notice in January 2023, with a February 1, 2025 withdrawal effective date. See "— MEMBERS – Contract Termination Payment and Relationship with Members."

Pursuant to the settlement agreement related to our Utility Member rates, we agreed to file a new rate schedule to our Utility Members after May 31, 2023. We filed such new rate filing in June 2023 with a requested January 1, 2024 effective date. Our new rate schedule is a formulaic rate that updates annually based on the next year's budget and it is then subsequently trued up to actual costs and sales when that data become available in the following year. In December 2023, FERC issued to us a deficiency letter with questions to answer. In January 2024, we filed answers to FERC's questions and again requested an effective date of our new rate schedule to be January 1, 2024. See " — RATE REGULATION."

Responsible Energy Plan and New ERA Program

In January 2020, we announced our Responsible Energy Plan, which will advance our clean energy transition. 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 sources;
- more local renewables for Utility Members through contract flexibility;
- promoting participation in a regional transmission organization; and
- expanding electric vehicle infrastructure and beneficial electrification.

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. If granted, we expect the funding will lead to significant reductions in system-wide greenhouse gas emissions, the addition of clean energy sources, and support for stranded assets, that we expect will assist us in providing affordable wholesale rates and reliable power to our Utility Members. Our proposal for this federal investment aims to transform our system and enhance grid reliability and resiliency while securing transition benefits and affordability for our Utility Members across multiple states. In March 2024, we received an Invitation to Proceed from the U.S. Department of Agriculture to complete the full New ERA Program application. The New ERA Program implements the $9.7 billion funded in the Inflation Reduction Act of 2022.

Power Supply and Transmission

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 have long-term purchase contracts with respect to various generating facilities. As of December 31, 2023, our diverse generation portfolio provides us with maximum available power of 4,323 MWs and is summarized in the table below:

Generation Portfolio (as of December 31, 2023)	Capacity (MW)	Percentage (%)
Coal-fired base load facilities	1,549	36
Renewables-contracts, including WAPA	1,366	32
Gas/oil-fired facilities	822	19
Other contracts, including Basin	586	13

We have three solar-based power purchase contracts totaling 340 MWs for facilities that are expected to achieve commercial operation in 2024 or early 2025. In March 2024, we expect to execute asset purchase agreements, along with engineering, procurement and construction contracts, for two solar-based facilities totaling 255 MWs that are expected to achieve commercial operation in 2025. In December 2023, we filed our Phase I 2023 ERP with the COPUC that included as part of our preferred scenario the addition of 1,250 MWs of additional renewable and battery storage through 2031, the early retirement of Craig Station by September 2028, and the early retirement of Springerville Unit 3 in September 2031. See "—POWER SUPPLY RESOURCES" and "PROPERTIES" for a description of our long-term purchase contracts and our generating facilities, including retirements of our generating facilities, and our resource plan.

After the retirement of Craig Station and the addition of new resources, as of December 31, 2028, we anticipate our generation portfolio to be the following:

Anticipated Generation Portfolio (as of December 31, 2028) (1)	**Capacity (MW)**	**Percentage (%)**
Renewables, including WAPA	2,101	45
Gas/oil-fired facilities	1,112	23
Coal-fired base load facilities	901	19
Other contracts, including Basin	561	12
Energy storage	60	1

(1) 340 MWs of renewables, 290 MWs of natural gas-fired, and 60 MWs of energy storage resources needed through 2028, based upon our preferred plan modeled in our Phase I 2023 ERP.

In addition to our diverse generation portfolio, as permitted by our wholesale electric service contracts with our Utility Members, as of December 31, 2023, our Utility Members own or control through long-term purchase power contracts approximately 138 MWs of operating distributed or renewable capacity that is used to deliver energy to our Utility Members' customers.

We transmit power to our Utility Members through resources that we own, lease or have undivided percentage interests in, or by wheeling power across lines owned by other transmission providers. We have ownership or capacity interests in approximately 5,827 miles of transmission lines and own or have major equipment ownership in 422 substations and switchyards. See "PROPERTIES" for a description of our transmission facilities.

Human Capital Resources

Employees are our most valuable resource and we endeavor to attract, develop, motivate and retain a diverse workforce and to develop, implement and support policies and programs that assist in this effort. We encourage superior performance by recognition and reward for employee ability and performance. As a cooperative, we do not have publicly traded stock and as a result do not have equity-based compensation programs. We compensate our employees through use of a total rewards package that includes base salary or hourly wages, retirement benefits, and health and welfare programs. Base salary and hourly wages are based upon performance and national salary data provided by various surveys, which include data from the labor market for positions with similar responsibilities.

We are committed to helping employees grow by offering training and development opportunities that support their progress. We encourage life-long learning and support this through on-the-job training, tuition reimbursement, apprenticeships and summer internships. We are also committed to the Cooperative Principle of Commitment to Community and provide opportunities for employees to contribute to various community programs and events as well as offer a paid volunteer day-off for employees to give back in their own communities.

We are committed to providing a respectful, safe and welcoming workplace where all employees' unique ideas and experiences are recognized. We facilitate this environment through open, honest communication and compliance with our Ethical Conduct and Conflict of Interest program. As we move toward a sustainable future, we are also working toward a diverse, equitable and inclusive culture for our current and future employees.

Safety is one of our core values. We attend to the safety of our employees, our contractors, and our communities before all other priorities. We strive to emphasize that safety is everyone's responsibility, regardless of job or work location. We aspire to prevent all fatalities and serious injuries. We put the protection of human life and the prevention of injuries above all else. We believe injuries and illnesses are preventable and have committed to supporting our employees with the tools, knowledge, and empowerment to complete their work safely and successfully. We regularly review and update our safety and health programs and safety management systems and implement actions with the goal of continually improving our safety and health performance. We have established an Executive Safety Council to review new initiatives, ideas, and protocols, encourage the sharing of safety moments at all organized meetings with five or more employees, and constantly work to educate all employees on the importance of safety.

Our average employee tenure across our organization was 11 years. In 2023, our turnover was 10.13 percent, a decrease from 16.84 percent in 2022. Retirements accounted for 2.44 percent of the turnover.

Including our subsidiaries, as of December 31, 2023, we employed 1,120 people, of which 215 were subject to collective bargaining agreements. As of December 31, 2023, none of these collective bargaining agreements will expire within one year. Since 2016, our number of employees has decreased by approximately 30 percent due to the closure of certain facilities, cost reduction efforts and other factors. We expect the number of employees to further decrease materially by 2028 with the closure of additional facilities by 2028. We supplement our workforce as needed through use of contingent workers.

MEMBERS

General

We have three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and Non-Utility Members. We currently have no Class B members, and therefore all our Utility Members are currently Class A members. Our Utility Members provide electric services, consisting of power supply and distribution services, to residential, commercial, industrial and agricultural customers primarily in Colorado, Nebraska, New Mexico and Wyoming. Our Utility Members' businesses involve the operation of substations, transformers and electric lines that deliver power to their customers. We currently have 42 Utility Members. Our Utility Members and the states within which they primarily provide electric service are as follows:

Colorado:	
Empire Electric Association, Inc.	San Isabel Electric Association, Inc.
Gunnison County Electric Association	San Luis Valley Rural Electric Cooperative, Inc.
Highline Electric Association	San Miguel Power Association, Inc.
K.C. Electric Association	Sangre de Cristo Electric Association, Inc.
La Plata Electric Association, Inc.	Southeast Colorado Power Association
Morgan County Rural Electric Association	United Power, Inc.
Mountain Parks Electric, Inc.	White River Electric Association, Inc.
Mountain View Electric Association, Inc.	Y-W Electric Association, Inc.
Poudre Valley Rural Electric Association, Inc.	

Nebraska:	
Chimney Rock Public Power District	Panhandle Rural Electric Membership Association
The Midwest Electric Cooperative Corporation	Roosevelt Public Power District
Northwest Rural Public Power District	Wheat Belt Public Power District

New Mexico:	
Central New Mexico Electric Cooperative, Inc.	Otero County Electric Cooperative, Inc.
Columbus Electric Cooperative, Inc.	Sierra Electric Cooperative, Inc.
Continental Divide Electric Cooperative, Inc.	Socorro Electric Cooperative, Inc.
Jemez Mountains Electric Cooperative, Inc.	Southwestern Electric Cooperative, Inc.
Mora-San Miguel Electric Cooperative, Inc.	Springer Electric Cooperative, Inc.
Northern Rio Arriba Electric Cooperative, Inc.	

Wyoming:	
Big Horn Rural Electric Company	High West Energy, Inc.
Carbon Power & Light, Inc.	Niobrara Electric Association, Inc.
Garland Light & Power Company	Wheatland Rural Electric Association
High Plains Power, Inc.	Wyrulec Company

We also currently have three Non-Utility Members: Ellgen Ranch Company, MIECO, Inc., and Olson's Greenhouses of Colorado, LLC. Ellgen Ranch Company is located in Colorado and is a party to ranch leases with Colowyo Coal. MIECO, Inc. is a California-based company that markets natural gas nationwide and is a major supplier of gas to our natural gas-fired generating facilities. Olson's Greenhouses of Colorado, LLC is headquartered in Utah and conducts business in Colorado. Olson's Greenhouses of Colorado, LLC has a contract to purchase thermal energy from us and reuses the waste steam that is generated from the J.M. Shafer Generating Station to heat its greenhouses.

Bylaws and Classes of Membership

Our Bylaws require each Utility Member, unless otherwise specified in a written agreement or the terms of our 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 Bylaws allow our Board to establish one or more classes of membership in addition to the all-requirements class of membership. However, the representation on our Board of any additional classes of membership would be determined by a vote of the Members at a membership meeting. In 2019, our Board established a non-utility membership class and authorized entering into membership agreements with Non-Utility Members. Non-Utility Members, as set forth in the membership agreements with such Non-Utility Members, have a right to vote at membership meetings, have rights to patronage capital, and have rights to liquidation proceeds, but have waived and have no right to representation on our Board. The non-utility membership class is intended to consist of entities that do not purchase power and energy from us and do not operate electric distribution systems. Our Bylaws limit the number of Non-Utility Members to no greater than ten. We currently have three Non-Utility Members. We may add new members in the future.

In 2020, our Board established the Class B - utility partial requirements membership class and named the existing all requirements membership class the Class A - utility full requirements members. Both classes of membership are full-requirements transmission members. We currently have 42 Class A members and no Class B members. See "— Wholesale Electric Service Contracts (Partial Requirements) - Class B members" for additional discussion regarding partial requirements. Our Members approved that the Class B members have representation on our Board if such Class B member purchases at least 65 percent of capacity from us.

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. See "BUSINESS – MEMBERS — Contract Termination Payment and Relationship with Members." for additional discussion regarding Member withdrawals.

Wholesale Electric Service Contracts (Full Requirements) - Class A members

Our revenues are derived primarily from the sale of wholesale electric service to our Utility Members pursuant to long-term contracts. These substantially similar contracts with our 42 Utility Members extend through 2050. The wholesale electric service contracts are subject to automatic extension thereafter until either party provides at least two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive from us, at least 95 percent of the power it requires for the operation of its system, except for sources such as photovoltaic cells, fuel cells, or others that are not connected to such Utility Member's distribution or transmission system. Each Utility Member may elect to provide up to 5 percent of its requirements from distributed or renewable generation owned or controlled by the Utility Member. As of December 31, 2023, 21 Utility Members have enrolled in this program with capacity totaling approximately 141 MWs, of which 138 MWs are in operation. See also "— Responsible Energy Plan" for a description of our clean energy transition.

Our Utility Members' demand for energy is influenced by seasonal weather conditions. Historically, our peak load conditions have occurred during the months of June through August, when irrigation load is the highest. Our summer peak load conditions depend on summer temperatures and the amount of precipitation during the growing season (generally May through September). Relatively higher summer or lower winter temperatures tend to increase the demand and usage of electricity for heating, air conditioning and irrigation. Mild weather generally reduces the demand and usage of electricity because heating, air conditioning and irrigation systems are operated less frequently.

The table below shows our Utility Members' aggregate coincident peak demand for the years 2019 through 2023 and the amount of energy that we supplied them. Our Utility Members' 2023 peak demand decreased 1.3 percent compared to 2022 and the annual amount of energy we sold to our Utility Members in 2023 increased 0.03 percent compared to 2022.

Year	Utility Members' Peak Demand (MW) (1)	Amount of Energy Sold (MWh) (1)
2023	3,030	16,530,385
2022	3,071	16,525,315
2021	2,974	15,676,830
2020	2,896	15,884,777
2019	3,009	16,412,525

(1) Includes peak demand of and energy sales to Delta-Montrose Electric Association through June 30, 2020.

Subject to certain force majeure conditions, we are required under the wholesale electric service contracts to use reasonable diligence to provide a constant and uninterrupted supply of electric service to our Utility Members. If our generation and other sources of supply are inadequate to serve all of our Utility Members' demand and we are unable to secure additional sources of supply, we are permitted to interrupt service to our Utility Members in accordance with a written policy established by our Board. We are currently able to provide all the requirements of our Utility Members and intend to construct the necessary facilities or make other arrangements to continue to do so.

The wholesale electric service contracts we have with our Utility Members provide that our Utility Members shall pay us for electric service at rates and on the terms and conditions established by our Board at levels sufficient to produce revenues, together with revenues from all other sources, to meet our cost of operation, including reasonable reserves, debt and lease service, and development of our equity. See "— RATE REGULATION." Our Utility Members are obligated to pay us monthly for the power, energy and transmission service we supply to them. Revenue from one Utility Member, United Power, comprised 19.6 percent of our Utility Member revenue and 16.2 percent of our operating revenue in 2023. No other Utility Member exceeded 10 percent of our Utility Member revenue or our operating revenue in 2023. Payments due to us under the wholesale electric service contracts are pledged and assigned to secure the obligations secured under our Master Indenture. A Utility Member cannot resell at wholesale any of the electric energy delivered to it under the wholesale electric service contract, unless such resale is approved by our Board or provided for in a schedule to the wholesale electric service contract.

The wholesale electric service contracts also provide for us to establish a committee every 5 years to review the wholesale electric service contracts for the purposes of making recommendations to our Board concerning any suggested modifications. The last contract committee regularly met in 2019 and into the first part of 2020 to discuss alternative contracts for our Utility Members, including partial requirements contracts. As part of the contract committee considering alternative contracts with our Utility Members, our Board also authorized the contract committee to consider alternative methods to determine the amount a Utility Member must pay to terminate its wholesale electric service contract and withdraw from membership. The contract committee, consisting of a representative from each Utility Member, recommended to our Board the community solar program, the partial requirements option, including the buy-down payment methodology, and the methodology to calculate a contract termination payment. The most recent contract committee began in March 2024.

The community solar program provided for a Utility Member to own or control, through a power purchase contract, a solar photovoltaic generation project that is intended to be marketed by the Utility Member under subscription arrangement to the Utility Member's retail customers. The community solar program was in addition to the 5 percent self-supply provision of the wholesale electric service contracts. The community solar program was one of the four reserved issues as part of the settlement agreement related to our Utility Members stated rate. In FERC's August 2023 order on the four reserved issues, FERC ruled that we failed to demonstrate that the economic terms of our community solar program were just and reasonable. Only one Utility Member executed a contract related to this program for a community solar project and that contract terminated at the end of 2023. The Utility Member now utilizes a portion of the 5 percent of its requirements from distributed or renewable generation owned or controlled by the Utility Member for its community solar project.

We and our Utility Members are subject to regulations issued by FERC pursuant to PURPA with respect to the purchase of electricity from, and the sale of electricity to, qualifying facilities and co-generators. Our Board policy sets forth the terms for us to bill the Utility Member for fixed cost equalization to make up for the lost revenue that we forego as a result of the qualifying facilities sales to the Utility Member in excess of the 5 percent self-supply provision of the wholesale electric service contract. As part of the waiver of applicable FERC regulations approved by FERC involving us and 30 of our Utility Members, we will stand in place of those Utility Members to purchase capacity and energy from qualifying facilities that interconnect to distribution systems of those Utility Members who are participating in the waiver filing. We will make such purchase at a rate equal to our full avoided cost. As part of the waiver program, those participating Utility Members will sell supplementary, back-up, and maintenance power to the qualifying facilities.

Wholesale Electric Service Contracts (Partial Requirements) - Class B members

Our Board has established the Class B - utility partial requirements membership class. In 2020, we filed with FERC a buy-down payment methodology tariff and our Board policy to implement a partial requirements option. Under the initial partial requirements membership construct, Utility Members could request to self-supply up to approximately 50 percent of their load requirements, subject to availability in the open season, in addition to the current 5 percent self-supply provision under the wholesale electric service contract and the then community solar program. A Utility Member that chose the partial requirements option would be obligated to make a buy-down payment to us. During our partial requirements "open season," a total of six Utility Members were allocated an aggregate of 300 MWs of self-supply.

The buy-down payment methodology tariff and Board policy were accepted by FERC, subject to refund, and FERC referred it to FERC’s hearing and settlement procedures. In June 2023, we filed with FERC a notice of cancellation of the buy-down payment methodology tariffs and Board policy to be effective August 28, 2023, stating such tariff and policy should no longer be a mechanism for Utility Members to self-supply a portion of their load requirements. In August 2023, FERC accepted our notice of cancellation. We and our Utility Members continue to evaluate the structure of implementing the partial requirements option that may be re-filed with FERC.

Utility Members’ Service Territories

Our Utility Members’ service territories are diverse, covering large portions of Colorado, Nebraska, New Mexico and Wyoming and very small portions of Arizona, Montana, and Utah. In accordance with state regulations, our Utility Members have exclusive rights to provide electric service to retail customers within designated service territories. In Colorado, our Utility Members’ service territories extend throughout the state and encompass suburban, rural, industrial, agricultural and mining areas. In Nebraska, our Utility Members’ service territories are comprised primarily of rural residential and farm customers in the western part of the state. In New Mexico, our Utility Members’ service territories extend throughout the northern, southern, central and western parts of the state, serving agricultural, rural residential, suburban, small commercial and mining customers. In Wyoming, our Utility Members’ service territories extend from the north central to the southeastern part of the state and encompass rural residential, agricultural and mining areas. The differences in customer bases, economic sectors, climates and weather patterns of our Utility Members’ service territories creates diversity within our system.

Eastern and Western Interconnection

North America is comprised of three major power grids, including the Western Interconnection and the Eastern Interconnection. The Western and Eastern Interconnection operate almost independently of each other with multiple direct current ties between the two grids. We have transmission facilities and serve our Utility Members’ load in both the Western and Eastern Interconnection. In 2023, approximately 3.9 percent of our total load is located in the Eastern Interconnection. Our generating facilities are located in the Western Interconnection and generally isolated from our Utility Members’ load in the Eastern Interconnection. We purchase, under a long-term purchase contract with Basin, almost all the power which we require to serve our Utility Members’ load in the Eastern Interconnection. See "— POWER SUPPLY RESOURCES — Purchased Power."

Contract Termination Payment and Relationship with Members

We are a cooperative corporation, and our Members are not our subsidiaries. We have no legal interest in, or obligation with respect to, any of the assets, liabilities, equity, revenue or margins of our Members except with respect to the obligations of our Members under their respective agreements with us. We have no control over or the right, ability or authority to control the electric facilities, operations, or maintenance practices of our Utility Members. Pursuant to our Bylaws, we and our Members disclaim any intent or agreement to be a partnership, joint venture, single or joint enterprise, or any other business form, except that of a cooperative corporation and member. The revenues of our Members are not pledged to us.

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 April 2020, our Board approved a methodology to calculate a contract termination payment designed to leave remaining Utility Members in the same economic position after a Utility Member terminates its wholesale electric service contract as the remaining Utility Members would have been had the Utility Member not terminated the contract. In June 2020, FERC accepted our contract termination payment methodology, subject to refund, and referred it to FERC's hearing and settlement judge procedures.

In late 2020, certain Utility Members formally requested a contract termination payment amount for planning purposes. Because the tariff then on file with FERC did not require us to prepare purely informational contract termination payment amounts for Utility Members, we respectfully declined to do so. In late February 2021, seven of our Utility Members filed a complaint with FERC seeking an order requiring us to prepare the contract termination payment amounts on an expedited basis. In March 2021, we filed a motion to dismiss and answer. In December 2023, FERC dismissed the complaint proceeding as moot as part of its December 2023 order on our contract termination payment methodology.

In June 2021, FERC issued a show cause order to us regarding our contract termination payment calculation and specifically regarding procedures for our Utility Members to obtain such calculations prior to making their termination decision. In July 2021, we filed our response to the show cause order and described a plan to file a simpler and more transparent modified contract termination methodology approved by our Board. FERC dismissed the show cause proceeding as moot as part of its December 2023 order on our contract termination payment methodology.

In September 2021, we filed with FERC as a rate schedule a modified contract termination payment methodology tariff. The modified methodology eliminates our Board's discretion over a Utility Member's withdrawal and provides a clear procedure and direct path to obtain a contract termination payment calculation without any delay or fees. The modified methodology was designed to protect the financial interests of our remaining Utility Members if a Utility Member elects to withdraw from membership in us. Our September 2021 tariff filing included requirements for a two-year notice and the payment of a contract termination payment. In simple terms, our modified contract termination payment amount is the greater of (i) the withdrawing Utility Member's debt covenant obligation, and (ii) our lost revenue, which is the projected revenue the withdrawing Utility Member contractually agreed to pay over the remaining term of its wholesale electric service contract, less certain offsetting revenues we could earn by reselling the withdrawing Utility Member's share of energy and capacity and the net present value of the withdrawing Utility Member's patronage capital.

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.

A hearing on our modified contract termination payment methodology occurred in May 2022 before an administrative law judge at FERC. We, United Power, certain of our Utility Members, other parties, and FERC trial staff all presented different contract termination payment methodologies or adjustments thereto. In September 2022, the administrative law judge issued an initial decision and endorsed the FERC trial staff balance sheet methodology, with significant adjustments suggested by us. In October 2022, we, United Power, certain other Utility Members, and other parties filed exceptions to the initial decision.

In December 2023, FERC issued an order on the initial decision and adopted a further modified balance sheet approach for the contract termination payment methodology. In January 2024, we, United Power, MPEI, and others filed requests for rehearing with FERC of its December 2023 order on the contract termination payment methodology. Our request for rehearing included FERC's rejection of our lost revenue approach and also certain clarifications. In February 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.

In January 2024, we filed a revised rate schedule with FERC with the contract termination methodology based upon FERC's December 2023 order that adopted a further modified balance sheet approach for the contract termination payment methodology. The revised rate schedule uses our FERC financials and distinguishes between Utility Members served on the Western and Eastern Interconnection. For Utility Members served solely on the Western Interconnection, the withdrawing Utility Member's contract termination payment is equal to the Utility Member's pro rata share, based upon Utility Member billing, of our long-term debt and certain other liabilities and also the Utility Member's pro rata share of our power purchase obligations in the Western Interconnection. The power purchase obligations are based upon the difference between the weighted average contracted-for prices and the projected market prices for each category of power purchase contracts, with the Utility Member's option to remarket, broker, or sleeve certain of our power purchase contracts. For withdrawing Utility Members in the Western Interconnection, we will create a regulatory liability for the OATT transmission related debt and provide a transmission credit, plus interest at FERC's proscribed interest rate, on the withdrawing Utility Member's post-withdrawal OATT service bills from us, as the transmission provider.

For Utility Members served solely on the Eastern Interconnection, the withdrawing Utility Member's contract termination payment is equal to the difference between the weighted average contracted-for prices for any power purchase contracts serving Eastern Interconnection member load, primarily the Wholesale Power Contract for the Eastern Interconnection with Basin, and projected market prices. The withdrawing Utility Member's payment also includes the negotiated amount of any radial facilities used to serve such Utility Member, which Utility Member is required to purchase from us. For Utility Members served in both the Western and Eastern Interconnection, the contract termination payment includes both parts of the calculation for Western and Eastern Interconnection Utility Members.

Withdrawing Utility Member may either choose to continue receiving accrued allocated patronage capital from us after their withdrawal when our Board retires patronage capital or take a discounted lump sum payment of their allocated patronage capital. If the Utility Member chooses the discounted lump sum option, the contract termination payment is reduced by such lump sum amount.

In February 2024, United Power, NRPPD, MPEI, and LPEA filed protests disputing certain parts of our January 2024 revised rate schedule and our calculation of the contract termination payment applicable to them.

In April 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 January 2024, we filed with FERC an unexecuted Withdrawal Agreement between us and United Power so that FERC may resolve the issues on which the parties could not agree. We requested that FERC accept the Withdrawal Agreement with an effective date of April 1, 2024. The Withdrawal Agreement describes the practical action items and related rights and obligations of the parties involved with effectuating the withdrawal of United Power from membership in us. The Withdrawal Agreement specifies an estimated contract termination payment amount of $627,630,197.00 that was calculated in accordance with our compliance filing for the revised rate schedule that was filed with FERC in January 2024 and includes the reduction of United Power’s estimated discounted lump sum payment of its allocated patronage capital. This amount is estimated because the lump sum patronage capital credit and regulatory liabilities credit that are part of the inputs in the contract termination payment are estimates. At least 30 days prior to May 1, 2024, we will provide United Power a finalized amount reflecting adjustments for patronage capital credit and regulatory liabilities credit or as otherwise directed by FERC. In February 2024, United Power filed a protest disputing the amount and calculation of the contract termination payment included in the Withdrawal Agreement.

In February 2024, Basin filed with the U.S. District Court District of North Dakota Eastern Division a motion for preliminary injunction that would enjoin us from disposing of our assets in the Eastern Interconnection in violation of our Wholesale Power Contract for the Eastern Interconnection with Basin. Basin's preliminary injunction seeks to preclude us from allowing a Utility Member in the Eastern Interconnection, including NRPPD, from terminating its wholesale electric service contract with us prior to the end of 2050. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

In February 2024, we filed with FERC an unexecuted Withdrawal Agreement between us and NRPPD because we were not able to agree on all terms. We requested that FERC accept the Withdrawal Agreement with an effective date of April 28, 2024. The Withdrawal Agreement describes the practical action items and related rights and obligations of the parties involved with effectuating the withdrawal of NRPPD from membership in us, including the purchase by NRPPD from us of certain facilities. The Withdrawal Agreement provides that the withdrawal of NRPPD is subject to NRPPD’s payment of the contract termination payment amount and that no court or other adjudicative authority has issued an order enjoining us from allowing a Utility Member, such as NRPPD, to withdraw from membership in us or terminate its wholesale electric service contract or determining that doing so would breach the Wholesale Power Contract for the Eastern Interconnection with Basin.

In July 2021, United Power's first amended complaint for declaratory judgement and damages against us and our Non-Utility Members was deemed filed alleging, among other things, that the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void and that we have breached our Bylaws and our wholesale electric service contract with United Power. In December 2023, we and United Power executed a formal settlement agreement and related agreements related to power and asset sales to United Power. As part of the settlement agreement, the parties filed a joint dismissal of all claims related to this litigation with prejudice, and the court granted the motion and dismissed the litigation. The asset sale, which is contingent on FERC's approval under section 203 of the FPA approval and United Power's withdrawal from us and payment of the contract termination amount, provides for us to sell to United Power certain facilities used to serve United Power's load for $75 million. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

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. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

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 have made great strides implementing the plan, with highlights from 2023 including:

- Reduce emissions – We retired Escalante Station in 2020 and have announced the retirement of Craig Station by 2030. In Colorado, by 2030 and relative to 2005 levels, we are targeting a 100 percent reduction in CO_2 emissions from our owned coal generation, a 90 percent reduction in CO_2 emissions across generation we own or operate, and an 80 percent reduction in CO_2 emissions associated with state wholesale electric sales.
    - *Progress in 2023*: We submitted to the COPUC our 2023 Electric Resource Plan that included as part of our preferred IRA scenario the early retirement of Craig Station by September 2028 and the early retirement of Springerville Unit 3 in September 2031. The reduction in CO_2 emissions associated with Colorado wholesale electric sales would increase to 89 percent by 2030 relative to a 2005 baseline.

- Increase clean energy – Between 2019 and 2025, we expect to bring nearly 1,000 MWs of utility scale wind and solar projects online, doubling our system to almost 2,000 MWs. By 2030, our goal is that 70 percent of the energy supplied to Utility Members system-wide will be from clean sources.
    - *Progress in 2023*: Our preferred IRA scenario as part of our Phase I 2023 ERP filed with the COPUC includes adding 1,250 MWs of additional renewable and battery storage through 2031.

- Extend clean grid benefits – We are expanding programs to help our Utility Members' rural consumers save money and energy while cutting emissions through use of electric vehicles, energy efficiency, beneficial electrification and other initiatives.
    - *Progress in 2023*: Working with our Utility Members, we achieved approximately 39.1 gigawatts of incremental energy efficiency savings in 2023, exceeding our target of 39.0 gigawatts for our Colorado Utility Members in our 2020 Electric Resource Plan settlement agreement.

- Increase member flexibility – We have been working together with our Utility Members to develop a more flexible contract structure so they can self-supply more power than ever before.
    - *Progress in 2023*: We and our Utility Members continue to evaluate the structure of implementing the partial requirements option.

- Employee and community support – Our efforts include retraining and transition support for employees affected by facility retirements and working with impacted communities to find meaningful economic development opportunities. We also work with local, state and federal leaders to support a just transition from coal.
    - *Progress in 2023*: With state and local leaders, we continued the discussion using a facilitator to explore community assistance opportunities for the City of Craig and Moffat County, in preparation for the retirement of Craig Station by 2030.

- Other elements – As we implement our Responsible Energy Plan, our goal is to maintain affordable rates for Utility Members in all states. We are also continuing to promote participation in a regional transmission organization in the West to reliably, efficiently, and cost-effectively integrate more renewables into the grid, and are striving for 100 percent clean energy in Colorado by 2040.
    - *Progress in 2023:* We submitted a Letter of Interest to apply for funding through the New Era Program that, if granted, we expect will lead to significant reductions in our greenhouse gas emissions, the addition of clean energy sources, and support for stranded assets, that we expect will assist us in providing affordable wholesale rates and reliable power to our Utility Members as we transition. We announced our commitment, along with six other western utilities, to become a full member of the SPP regional transmission organization expansion into the Western Interconnection.

Competition

In accordance with state regulations, our Utility Members have exclusive rights to provide electric service to retail customers within designated service territories. States in which our Utility Members' service territories are located have not enacted retail competition legislation. Federal legislation could mandate retail choice in every state. Our Utility Members are subject to customer conservation and energy efficiency activities, as well as initiatives to utilize alternative energy sources, including self-generation, or otherwise bypass our Utility Members' systems. Our Utility Members are also subject to competition for attracting new load as potential customers may locate their facilities in our Utility Member's designated service territory or the service territory of a neighboring utility.

In 1992, we entered into an agreement expiring in December 2025 with PSCO and PacifiCorp, two of the principal investor-owned utilities adjacent to our Utility Members' service territories in Wyoming and Colorado, that provides, among other things, that each of PSCO, PacifiCorp and us will:

- not make any hostile or unfriendly attempt to acquire or take over any stock or assets of any member served by another party to the agreement;
- respect all certificates of convenience and necessity and not attempt to serve any consumers within another's certified area; and
- seek to preserve territorial boundaries when threatened by municipal annexations.

We and our Utility Members are subject to competition from third party energy remarketing companies. Energy remarketing companies are targeting our Utility Members and the communities our Utility Members serve by claiming to be able to offer lower priced and cleaner wholesale electric power. This includes assisting our Utility Members in seeking to withdraw from membership in us and financing the withdrawal payment by our Utility Members. It also includes assisting some municipalities and tribes that our Utility Members serve by helping them create electric utilities.

RATE REGULATION

New Rate Developments

In August 2021, FERC approved our settlement agreement related to our Utility Members stated rate, including our wholesale electric service contracts and certain of our Board policies filed with FERC. With the exception of four reserved issues contingent on United Power being a settling party, the settlement resolved all issues set for hearing and settlement procedures related to our Utility Member rates. Three of the reserved issues were related to the transmission component of our rates and the fourth relates to our community solar program. Additionally, with the exception of one reserved issue regarding transmission demand charges applicable to certain electric storage resources, each of the reserved issues had a prospective effect only, with the intent that any FERC rulings would be implemented in future rate filings.

A hearing on the four reserved issues occurred in March 2022 before an administrative law judge at FERC and an initial decision was issued by an administrative law judge in May 2022. In June 2022, we, United Power, and certain other Utility Members filed exceptions to the initial decision. In August 2023, FERC issued an order on initial decision that provides that we must also unbundle in our bills to our Utility Members our transmission and ancillary costs. Related to us directly assigning to our Utility Members the costs of our non-network radial facilities that do not meet FERC's standards for being included in our rolled-in transmission demand rate, FERC's order provided us flexibility in how we may justify that such costs should be allocated. In the order, FERC noted that we should perform an assessment of non-network transmission facilities and demonstrate that these facilities are eligible to be rolled into the transmission rate or should be direct assigned to our Utility Members. In addition, the FERC order provided that we failed to demonstrate that the economic terms of our community solar program were just and reasonable, but the finding was without prejudice to further justification by us. With regard to the reserved issue concerning transmission demand charges applicable to certain electric storage resources, the FERC order agreed with our Board policy of billing Utility Members for the transmission demand costs that includes all of a Utility Member's transmission demand, including such Utility Member's electric storage resource. NRPPD filed a motion for reconsideration with FERC, and that motion was denied by FERC by operation of law.

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. Our formula rate is designed to collect our projected annual revenue requirements, including Board-approved margins, with an annual true-up mechanism to ensure that the revenue collected accurately reflects our actual costs incurred. The rate template will be updated annually with the next year's budget and then trued up to actuals annually after the end of each rate year. The formula rate is designed for annual rate adjustments to account for variations in load and costs without additional FERC approval for each annual adjustment. The new rate components are similar to the existing Class A rate schedule (A-40) with a few exceptions. The exceptions include a further unbundling of our transmission/delivery demand rate into two demand components, one for network transmission costs and another for non-network transmission costs. This change does not shift costs or change the overall transmission bill. We believe that it provides transparency to Utility Members to see what components of transmission are driving costs. Another rate change is from the average and excess demand method to a peaker methodology, with the peaker methodology setting a demand charge set to reflect the cost of an additional peaking generating facility. This method provides a pricing signal to Utility Members to manage peak usage by creating credits for peak shifting equal to the cost of a peaking generating facility rather the full system demand cost. An additional major change in the rate was the addition of a new financial metric for margin calculation. In addition to a minimum DSR of at least 1.15 and ECR of at least 20 percent at the end of each fiscal year, the rate uses a $20 million margin minimum to assure financial resources are available. A majority of our Utility Members and other parties have intervened in our rate filing with FERC. In November 2023, we filed a limited amendment with FERC to our new Class A rate schedule in response to FERC's August 2023 order on initial decision related to the four reserved issues concerning our Utility Members stated rate. The limited amendment addressed the reserved issue of unbundling costs in our bills to our Utility Members, in particular ancillary costs, and the reserved issue related to cost allocation of non-networked transmission facilities.

In December 2023, FERC issued to us a deficiency letter on our formula rate filing with six questions to answer. In January 2024, we filed answers to FERC's questions and again requested an effective date of our new rate schedule to be January 1, 2024. Five questions focused on our use of rolled-in rates and one question focused on our community solar program which was not at issue in the filed rates. In February 2024, some of our Utility Members filed comments or a protest in response to our answers to FERC's questions.

Rate Regulation

The wholesale electric service we provide to our Utility Members are at rates established by our Board, but such rates are subject to FERC acceptance or approval. Our wholesale electric service contracts with our Utility Members provide that rates paid by our Utility Members for the wholesale electric service we supply to them must be set at levels sufficient to produce revenues, together with revenues from all other sources, to meet our cost of operation, including reasonable reserves, debt and lease service, and development of equity.

We provide wholesale electric power to non-members at contractual rates under long-term arrangements and at market prices in short-term transactions in the WACM, PSCO and PNM balancing authority areas, subject to FERC market-based rate authority.

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 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 Member 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 is billed based upon a price per kWh of physical energy delivered, and the two demand rates (a generation demand and a transmission/delivery demand) are 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.

Our Class A rate schedule (A-40) was filed at FERC as a “stated rate.” As part of the FERC approved settlement agreement, commencing March 1, 2022, the charges making up our Class A rate schedule decreased by an additional 2 percent until the date a new Class A wholesale rate schedule is approved or accepted by FERC and goes into effect.

Rate Policy

Under our Master Indenture, we are required to establish rates annually that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis, and we are also required to maintain an ECR of at least 18 percent at the end of each fiscal year. 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.

Our revised Board Policy for Financial Goals and Capital Credits, approved in connection with our Board’s approval of our new Class A rate schedule (A-41), includes three financial ratio goals for which Tri-State 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 management proposes rates that are expected to adequately recover our annual Utility Member revenue requirements contingent upon load projections and a budget approved annually by our Board. Our Board reviews the budget and our underlying rates on an annual basis in accordance with our financial goals and rate objectives, and in accordance with the financial covenants contained in our debt instruments. Our Master Indenture also requires that we review rates promptly at any point during the year upon any material change in circumstances which was not contemplated during the annual review of Utility Member rates. Any rate changes will be filed at FERC for their acceptance.

The following table shows our average Utility Member revenue/kWh for the years 2019 through 2023. The average Utility Member revenue/kWh is our total Utility Members' electric sales revenue in a given year divided by the total kilowatt hours sold to our Utility Members in that given year. The average Utility Member revenue/kWh does not represent the actual energy and demand rate components established by our Board and paid by our Utility Members for the years 2019 through 2023.

Year	Average Utility Member Revenue (Cents/kWh)
2023	7.310
2022	7.342
2021	7.408
2020	7.531
2019	7.547

Other FERC Regulation

In addition to FERC's jurisdiction over our wholesale rates to our Utility Members, cost-based rate tariff and market-based rate authority, FERC also regulates the issuance of securities and assumption of liabilities by us, as well as mergers, consolidations, the acquisitions of securities of other utilities, and the disposition of property subject to FERC jurisdiction. Under FERC regulations, we are prohibited from selling, leasing, or otherwise disposing of the whole of our facilities subject to FERC jurisdiction, or any part of such facilities having a value in excess of $10 million without having FERC approval. We are also required to seek FERC approval prior to merging or consolidating our facilities with those of any other entity having a value in excess of $10 million. FERC also regulates certain of our transmission and generation operations, including reliability, transmission of electricity, and transmission planning. See "— TRANSMISSION."

POWER SUPPLY RESOURCES

We provide electric power to our Utility Members through a combination of generating facilities that we own, lease, or have undivided percentage interests in, and through the purchase of electric power pursuant to power purchase contracts and purchases on the open market.

In 2023, 48.2 percent of our energy available for sale was provided by our generation and 51.8 percent by purchased power. Based upon our preferred IRA scenario as part of our Phase I 2023 ERP, we expect to enter into additional renewable power purchase contracts. We estimate that by 2025, 50 percent of the energy our Utility Members use will come from clean sources.

Depending on our system requirements and contractual obligations, we are likely to both purchase and sell electric power during the same fiscal period. We use market transactions to optimize our position by routinely purchasing power when the market price is lower than our incremental production cost and routinely selling power to the short-term market when we have excess power available above our firm commitments to both Utility Members and non-members. We also use short-term market purchases during periods of generation outages at our facilities.

Generating Facilities

We own, lease or have undivided percentage interests in 1,549 MWs from coal-fired base load facilities and 822 MWs from gas/oil-fired facilities. See "PROPERTIES" for a description of our various generating facilities.

In September 2016, we announced that the owners of Craig Station Unit 1 intend to retire Craig Station Unit 1 by December 31, 2025, which includes our 102 MW share from such unit. In January 2020, we announced that our Board approved the early retirement of Craig Station Units 2 and 3. Our share of Craig Station Unit 2 is 98 MWs. We and the other joint owners of Craig Station Unit 2 intend to retire Craig Station Unit 2 by September 30, 2028. We own and operate the 448 MW Craig Station Unit 3. Based upon our preferred IRA scenario as part of our Phase I 2023 ERP, we intended to retire Craig Station Unit 3 by January 1, 2028. The early retirement of Craig Station is expected to impact approximately 175 employees.

Based upon our preferred IRA scenario as part of our Phase I 2023 ERP and subject to receipt of New ERA Program funding related to Springerville Unit 3 and reaching agreements with the applicable parties, we intended to retire Springerville Unit 3 by September 15, 2031.

In March 2024, we expect to execute an asset purchase agreement to purchase the 145 MW Axial Basin Solar project being developed located in northwestern Colorado located near the Colowyo Mine. We also expect to execute an asset purchase agreement to purchase the 110 MW Dolores Canyon Solar project being developed located in southwestern Colorado. Concurrent with execution of the purchase agreements, we also expect to execute engineering, procurement and constructions contracts with an affiliate of the developer of such projects, and these projects are expected to achieve commercial operation in 2025. The acquisition of these projects and commencement of physical construction is expected to commence in the first half of 2024. In November 2023, we filed for approval from the COPUC to acquire these projects. The COPUC approved this transaction in January 2024. Upon acquisition of these projects, our power purchase contracts for these projects will terminate.

Purchased Power

We supplement our capacity and energy requirements not supplied by our generating facilities through long-term purchase contracts and short-term energy purchases. Our largest long-term power purchase contracts are discussed below.

Renewables. We have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,381 MWs, including 674 MWs of wind-based power purchase contracts and 680 MWs of solar-based power purchase contracts, of which 786 MWs are in operation. The largest of these renewable power purchase contracts are summarized in the table below. A majority of our renewable power purchase contracts include the option for us to purchase the renewable facility at certain points during the term of the power purchase contract.

Facility Name	Location	Counterparty	Energy Source	Capacity (MW)	Year of Commercial Operation		Year of Contract Expiration	
Alta Luna Solar	New Mexico	TPE Alta Luna, LLC	Solar	25	2017		2042	
Axial Basin Solar (3)	Colorado	Axial Basin Solar, LLC	Solar	145	2024	(1)	2039	(2)
Carousel Wind Farm	Colorado	Carousel Wind Farm, LLC	Wind	150	2016		2041	
Cimarron Solar	New Mexico	Southern Turner Cimarron I, LLC	Solar	30	2010		2035	
Colorado Highlands Wind	Colorado	Colorado Highlands Wind, LLC	Wind	94	2012		2032	
Crossing Trails Wind	Colorado	Crossing Trails Wind Power Project, LLC	Wind	104	2021		2036	
Dolores Canyon Solar (3)	Colorado	Dolores Canyon, LLC	Solar	110	2024	(1)	2039	(2)
Escalante Solar	New Mexico	Escalante Solar, LLC	Solar	200	2024	(1)	2041	(2)
Kit Carson Windpower	Colorado	Kit Carson Windpower, LLC	Wind	51	2010		2030	
Niyol Wind	Colorado	Niyol Wind, LLC	Wind	200	2021		2041	
San Isabel Solar	Colorado	San Isabel Solar LLC	Solar	30	2016		2041	
Spanish Peaks Solar I	Colorado	Spanish Peaks Solar, LLC	Solar	100	2024	(1)	2039	(2)
Spanish Peaks Solar II	Colorado	Spanish Peaks II Solar, LLC	Solar	40	2024	(1)	2039	(2)
Twin Buttes II Wind	Colorado	Twin Buttes Wind II, LLC	Wind	75	2017		2042	

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(1) Our anticipated year of commercial operation.
(2) Our anticipated year of contract expiration based upon our anticipated year of commercial operation.
(3) In March 2024, we expect to execute asset purchase agreements for these two solar projects being developed and upon closing of the acquisition, these two power purchase contracts will terminate.

In addition to the renewable power purchase contracts in the table above, we have long-term renewable power purchase contracts with WAPA. Substantially all of our purchases from WAPA are hydroelectric based power made at cost-based rates under long-standing federal law under which WAPA sells power to cooperatives, municipal electric systems and certain other "preference" customers. WAPA markets and transmits the power to us pursuant to three contracts, (i) one contract relating to WAPA's Loveland Area Projects that terminates September 30, 2024 and replaced with a contract that commences delivery on October 1, 2024 and terminates September 30, 2054 and (ii) two contracts relating to WAPA's Salt Lake City Area Integrated Projects that terminate September 30, 2024 and replaced with one contract that commences delivery on October 1, 2024 and terminates September 30, 2057. The Loveland Area Projects generally consists of generation and transmission facilities located in the Missouri River Basin. The Salt Lake City Area Integrated Projects generally consists of generation and transmission facilities located in the Colorado River Basin. The following table shows the contractual long-term power delivery from WAPA in the summer season (April-September) and the winter season (October-March):

Resource:	Summer (MW)	Winter (MW)
Loveland Area Projects	349	285
Salt Lake City Area/Integrated Projects	231	247
Total	580	532

In 2021, WAPA notified us that effective December 1, 2021 through December 31, 2023, WAPA increased the Salt Lake City Area Integrated Projects capacity and energy rates by approximately 8 percent as well as decreased the capacity and energy allocations due to the drought impact in the southwest U.S. on hydro generation and replacement purchased power cost projections. WAPA moved from a seasonal notice of allocations to a quarterly notice of allocations due to the uncertainty of future hydro generation capability. In 2022, annual capacity and energy allocations were reduced by 33 percent compared to our full entitlement. However, in 2023, the WAPA capacity and energy allocations improved compared to 2022 due to exceptional precipitation. In 2023, annual capacity and energy allocations were reduced by 18 percent compared to our full entitlement. For the first quarter of 2024, our capacity allocations decreased by 11 percent compared to our full entitlement, while energy allocations for the first quarter of 2024 decreased by 27 percent compared to our full entitlement. Reservoir levels along with precipitation will be the driving factors in our future contract allocations.

Basin. In 2017, we entered into two new amended and restated wholesale power contracts with Basin. The new wholesale power contracts amended and restated a 1975 wholesale power contract with Basin and separated the prior 1975 wholesale power contract into two wholesale power contracts: one for the Western Interconnection and one for the Eastern Interconnection.

The wholesale power contract for the Eastern Interconnection provides the terms under which we purchase in the Eastern Interconnection all the power which we require to serve our Utility Members' load in the Eastern Interconnection other than a very small portion of Utility Members' load in the Eastern Interconnection in New Mexico. The Utility Members' peak load in the Eastern Interconnection in 2023 was approximately 318 MWs.

The wholesale power contract for the Western Interconnection provides the terms under which we purchase in the Western Interconnection fixed scheduled quantities of electric power and energy. The quantity of electric power and energy varies depending on the month and hour with a maximum of 268 MWs occurring during certain hours in July.

Both amended and restated wholesale power contracts continue through December 31, 2050 and are subject to automatic extension thereafter until either party provides at least five years' notice of its intent to terminate.

In addition to long-term power purchase contracts, we utilize market purchases to optimize our position by routinely purchasing power when the market price is lower than our incremental production cost. We also utilize short-term market purchases during periods of generation outages. In addition, we have hazard sharing arrangements with Platte River Power Authority and TEP, which provide for supply of power to us in the event of forced outages at specified generating facilities.

Power Sale Contracts

We have a long-term power sales contract to sell Salt River Project 100 MWs of power, contingent on the operation of Springerville Unit 3, which expires in August 2036.

In 2023, we entered into a tolling contract with a third party for the output of the two combustion turbines at Knutson Generating Station starting May 1, 2024 through December 2027, which is an arrangement whereby the purchaser provides its own natural gas for generation of electricity.

In anticipation of Utility Member withdrawals in 2024 and 2025, we have entered into multiple power sales contracts with third parties for the sale of excess capacity and energy, with certain transactions starting May 1, 2024. Certain of these power sales contracts are contingent upon United Power's withdrawal on May 1, 2024. We expect to enter additional power sales contracts in the future.

In addition to long-term power sales contracts, we routinely sell power to the short-term market when we have excess power available above our firm commitments to both Utility Members and non-members.

We are subject to varying degrees of competition related to the sale of excess power to non-members on both a short-term and long-term basis. We are subject to competition from regional utilities and merchant power suppliers with similar opportunities to generate and sell energy at market-based prices and larger trading entities that do not own or operate generating assets.

Energy Imbalance Markets

We have all our load in organized markets. Since February 2021, we have participated in SPP's Western Energy Imbalance Service market that generally covers our load and resources in Colorado, western Nebraska located in the Western Interconnection, and the eastern half of Wyoming. The market centrally dispatches energy from these participants through the region every five minutes. With PSCO's market commencement in April 2023, approximately 78 percent of our load is in this market.

We also participate in the CAISO Western Energy Imbalance Market. This affects our load and resources within the PNM balancing authority area, which is all our load and resources in New Mexico. We have registered our New Mexico resources and Springerville Unit 3 generation as participating resources with CAISO in order for our generation to participate in this imbalance market. We have a small amount of load located in the PacifiCorp balancing authority area in the CAISO Western Energy Imbalance Market.

Our load and transmission facilities in the Eastern Interconnection, largely in Nebraska, have been in the SPP regional transmission organization since 2016.

In September 2023, we announced our commitment, along with Basin, WAPA, Municipal Energy Agency of Nebraska, Deseret Power Electric Cooperative, Colorado Springs Utilities, and Platte River Power Authority, to become a full member of SPP's regional transmission organization expansion into the Western Interconnection. We expect the expansion of SPP's service territory from the Eastern Interconnection into the Western Interconnection to be completed in the first half of 2026 at which time certain of our load and transmission facilities in the Western Interconnection will be part of the SPP regional transmission organization. We believe a Western Interconnection regional transmission organization is necessary to achieve the full benefits of organized markets and to meet state laws and goals regarding reductions in CO_2 emissions.

Resource Planning

We continually evaluate potential resources required to serve the long-term requirements of our Utility Members. As part of our approach to resource planning, we evaluate various resource options, including the construction of new resources and long-term power purchase contracts. In evaluating future portfolio additions, we monitor market conditions, tax credit expiration schedules, impacts of current resources on reliable system operations and the operation of existing generation assets, transmission system capacity, our potential participation in a regional transmission organization in the Western Interconnection, and the regulatory requirements for meeting Electric Resource Plan rules, RPS and RES and other state laws and goals regarding reductions in CO_2 emissions.

In 2019, Colorado legislation was signed that requires us to file and obtain COPUC approval for our electric resource plan where the social cost of CO_2 emissions associated with our plan is a consideration, along with other factors. The process includes a Phase I and Phase II process. Our first Phase I Electric Resource Plan under the COPUC rules was filed with the COPUC in December 2020. In January 2022, we reached an unopposed comprehensive settlement agreement with the majority of intervening parties to the proceeding. In March 2022, the administrative law judge for the COPUC recommended approval of the settlement agreement and the approval became effective in April 2022. The settlement agreement sets emissions reduction targets for our wholesale electricity sales in Colorado as follows: at least 26 percent in 2025, 36 percent in 2026, 46 percent in 2027, and 80 percent in 2030, with respect to the verified 2005 baseline. The settlement agreement also implemented new energy efficiency and demand response targets.

With the settlement agreement approved, we began Phase II of our 2020 Electric Resource Plan and in May 2022 issued a request for proposals for capacity and energy bids, with a focus on projects that support emissions reductions. These projects would be scheduled to come online in 2025 or 2026. The bidding process closed in September 2022. In October 2022, we filed our 30-day report with the COPUC disclosing that we received 274 individual eligible bid proposals (156 total projects) from bidders. In February 2023, we filed our 2020 Electric Resource Plan Phase II implementation report identifying our preferred portfolio for resource acquisitions in the 2025-2026 timeframe. The Phase II modeling filed with the COPUC indicated selection of 200 MWs of new wind resources for 2026, subject to COPUC approval. A COPUC decision on Phase II was issued in June 2023 approving the new wind resource acquisition; however, in July 2023, we submitted a filing notifying the COPUC that the developers for both the selected bid and back-up wind bid had failed and the capacity would be re-bid as part of our next Phase II process for our 2023 Electric Resource Plan.

In December 2023, we filed our Phase I 2023 ERP with the COPUC, which contained our 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 take advantage of direct pay of federal tax benefits for renewable and storage resources by increasing our owned resources. Our preferred plan retires Craig 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 identified in our January 2022 settlement agreement related to Phase I of our 2020 Electric Resource Plan.

Fuel and Water Supply

Coal. We purchase coal under long-term contracts. See "PROPERTIES" for a description of our investments in coal mines. The following table summarizes the sources of our coal for each of our coal-fired generating facilities:

Generating Station	Mine	Contract End Date
Craig Station Units 1 and 2	Colowyo Mine	2029 (1)
Craig Station Unit 3	Colowyo Mine	2029 (1)
Laramie River Generating Station	Various, including Dry Fork Mine	2041
Springerville Unit 3	North Antelope Rochelle Mine	2024

(1) We expect to align the terminations of these contracts with the respective closure of the generation units.

Colowyo Mine. Mining operations in the South Taylor pit are completed and land is being reclaimed. Colowyo Coal, a subsidiary of ours, is now actively mining the Collom pit at the Colowyo Mine.

Reclamation Liabilities. In connection with our use of coal derived from coal mining facilities in which we have an ownership interest, including the Colowyo Mine and the New Horizon Mine, there are certain reclamation activities mandated by state and federal laws. These liabilities are recognized and recorded on our financial statements when required by accounting guidelines. We provide surety bonds from third party sureties for our reclamation obligations at the Colowyo Mine and the New Horizon Mine in accordance with Colorado requirements. The amounts of such bonds are based upon Colorado requirements and are different than the amount of liabilities recognized on our financial statements in accordance with GAAP.

Natural Gas. The majority of natural gas we purchase is to fill peak demands, and as replacement energy for forced outages and curtailments on coal units and renewable resources. We currently purchase the majority of our gas supplies on the spot market at fixed daily prices and on occasion we enter into forward fixed-price, fixed-quantity physical contracts. The majority of natural gas is purchased in the Cheyenne Hub area, which is in close proximity to the natural gas generating facilities we tend to utilize most frequently. This includes purchases from our Non-Utility Member, MIECO, Inc. Six major natural gas pipelines have interconnections at the Cheyenne Hub, and presently there is generally adequate supply at this location. Based on the regional forecast of production activities and pipeline capacity in the Rocky Mountain region, we presently anticipate that sufficient supplies of natural gas will generally be available in the foreseeable future. During extreme weather events, the availability of natural gas may be limited. We have a long-term natural gas transportation contract that provides firm rights to move natural gas from various receipt points to our facilities. Finally, we may utilize financial instruments to price hedge our forecasted natural gas requirements.

Oil. Distillate fuel for the Burlington, Limon, Knutson and Pyramid Generating Stations, all simple-cycle combustion turbine facilities, is purchased on the spot market from various suppliers. Oil is transported to the respective locations via truck.

Water Supply. We use varying amounts of water for the production of steam used to drive turbines that turn generators and produce electricity in our generating facilities. We maintain a water portfolio that supplies water from various sources for each of our generating facilities. This portfolio is adequate to meet the water supply requirements of our generating facilities.

Temporary supplies are also typically available on a short-term or annual basis from third-party water providers. Our generating facilities are located in the western part of the U.S. where demand for available water supplies is heavy, particularly in drought conditions. Litigation and disputes over water supplies are common and sometimes protracted, which can lead to uncertainty regarding any user's rights to available water supplies. If we become subject to adverse determinations in water rights litigation or to persistent drought conditions, we could be forced to acquire additional temporary or permanent water supplies or to curtail generation at our facilities.

TRANSMISSION

We have ownership or capacity interests in approximately 5,827 miles of transmission lines and own or have major equipment ownership in 422 substations and switchyards. See "PROPERTIES" for a description of our transmission facilities.

Our system is interconnected with those of other utilities, including WAPA, Nebraska Public Power District, Black Hills Colorado Electric, Inc., PacifiCorp, PSCO, Platte River Power Authority, Colorado Springs Utilities, Basin, TEP, PNM and Deseret Power Electric Cooperative. The majority of our transmission facilities operate as part of the Western Interconnection. The Western Interconnection consists of transmission assets that link generating facilities to load centers throughout the region. A small portion of our facilities support our load centers in the Eastern Interconnection. We continue to make the capital investment necessary to expand our transmission infrastructure and participate in many joint projects with other transmission owners to provide electric service to our Utility Members.

The FPA authorizes FERC to oversee the sale at wholesale and transmission of electricity in interstate commerce by public utilities, as that term is defined in the FPA. We are subject to the general "public utility" regulation of FERC under the FPA and are under FERC jurisdiction for rates and transmission service.

FERC requires public utilities to comply with several requirements, including the requirements to provide open access transmission service and engage in regional planning of transmission facilities. We are also subject to reporting obligations applicable to all electric utilities, other FERC orders, and FERC's oversight with respect to transmission planning, investment and siting, reliability standards, price transparency, and market manipulation. We are subject to regulations issued by FERC pursuant to the Energy Policy Act of 1992 and the Energy Policy Act of 2005 with respect to the provision of certain transmission services.

We are a member of SPP and have transferred operational authority (but not ownership) of our transmission facilities that are located in the Eastern Interconnection to SPP, a regional transmission organization. See "— POWER SUPPLY RESOURCES – Energy Imbalance Markets" regarding discussions of expanding SPP to the Western Interconnection.

Open Access Transmission Service

FERC requires public utilities to provide open access transmission service. Open access generally gives all potential users of the transmission grid an equal opportunity to obtain the transmission service necessary to support purchases or sales of electric energy, thereby promoting competition in wholesale energy markets. Use of our transmission facilities is governed by OATTs. Use of our Eastern Interconnection transmission facilities is governed by the SPP OATT and our costs of providing transmission service in the Eastern Interconnection are subject to review by FERC. Use of our Western Interconnection transmission facilities is governed by our OATT filed with FERC and our costs of providing transmission service in the Western Interconnection are subject to review by FERC.

FERC has additional oversight authority over us under Sections 210 and 211 of the FPA, which apply to all transmitting utilities. Under these sections, FERC may, upon application by a customer, compel a utility to provide interconnection and transmission service to that customer, subject to appropriate compensation. We have not been the subject of an order under these provisions of the FPA.

Transmission Planning

FERC has become increasingly involved in promoting the development of the transmission grid. In FERC Order No. 890, FERC expressly required coordinated transmission planning and established governing principles. We comply with this requirement through our participation in WECC, WestConnect, SPP, and other sub-regional transmission planning groups and processes. In FERC Order No. 1000, FERC required all public utilities to engage in regional and interregional transmission planning and cost allocation. We comply with Order No. 1000 by participating in regional and interregional transmission planning and cost allocation processes in SPP and WestConnect. WestConnect is a voluntary organization of transmission providers committed to assessing stakeholder needs in the Southwest. The participants in WestConnect own and operate transmission systems in all or part of the states of Arizona, New Mexico, Texas, Colorado, Nebraska, South Dakota, Wyoming, Utah, Nevada, and California.

FERC has also provided for rate incentives for public utilities as a means of encouraging investment in new transmission facilities. Recent approvals by FERC of rate incentives for transmission projects in our region and elsewhere have provided us with practical guidance as to the applicability of these incentives to potential future transmission projects.

Reliability

Section 215 of the FPA authorizes FERC to oversee the reliable operation of the nation's interconnected bulk power system. In 2007, FERC approved mandatory national reliability standards for administration by NERC. The national standards apply to all utilities that own, operate, and/or use generating or transmission facilities as part of the interconnected bulk power system. As an owner, operator and user of generation and transmission facilities, we are subject to some of these reliability standards. Under the national standards, utilities must, among other things, respond to emergencies within stated time periods, maintain prescribed levels of generation reserves, and follow instructions concerning load shedding. FERC also approved limited delegations of authority to six regional entities. We are registered in two of the six regional entities: WECC and MRO. In addition, our generating facilities are included in two regional reserve sharing pools: the Western Power Pool and the Southwest Reserve Sharing Group. These pools facilitate sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line.

We have an active compliance monitoring program that covers all aspects of our generation and transmission reliability responsibilities. We also collaborate with our Utility Members on areas where transmission and distribution system reliability responsibilities overlap. NERC and its regional entities, including WECC and MRO, periodically audit compliance with reliability standards. In addition to audits and spot-checks (unscheduled audits), NERC and its regional entities, including WECC and MRO, are also authorized to conduct other types of investigations, including requiring annual "self-certifications" of compliance with select reliability standards.

In 2021, we were audited by WECC and are scheduled for a future compliance audit in 2024 as part of a three-year routine audit cycle. WECC continues to evaluate the findings of the 2021 audit, however, we do not expect there to be any significant enforcement actions and we do not expect any financial penalties.

ENVIRONMENTAL REGULATION

We are subject to various federal, state and local laws, rules and regulations with regard to the following:

- air quality, including greenhouse gases;
- water quality; and
- other environmental matters.

These laws, rules and regulations often require us to undertake considerable efforts and incur substantial costs to maintain compliance and obtain licenses, permits and approvals from various federal, state and local agencies. To comply with existing environmental regulations, we expect that we will spend approximately $3.8 million through 2028 in efforts to maintain compliance. We estimate that we spend over $500,000 per year in permit-related fees, as well as increased operating costs to ensure compliance with environmental standards of the Clean Air Act, described below. If we fail to comply with these laws, regulations, licenses, permits or approvals, we could be held civilly or criminally liable.

Our operations are subject to environmental laws and regulations that are complex, change frequently and have become more stringent and numerous over time. Federal, state and local standards and procedures that regulate the environmental impact of our operations are subject to change. These changes may arise from continuing legislative, regulatory and judicial actions regarding such standards and procedures. Consequently, there is no assurance that environmental regulations applicable to our facilities will not become materially more stringent, or that we will always be able to obtain all required operating permits. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of our facilities that are not in compliance, including the shutting down of additional generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled. We cannot predict at this time whether any additional legislation or rules will be enacted which will affect our operations, and if such laws or rules are enacted, what the cost to us might be in the future because of such actions.

From time to time, we are alleged to be in violation or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. Additionally, we may need to deal with notices of violation, enforcement proceedings or challenges to construction or operating permits. In addition, we may be involved in legal proceedings arising in the ordinary course of business.

Since 1971, we have had in place a Board Policy for Environmental Compliance that is reviewed periodically by our Board. The policy commits us to comply with all environmental laws and regulations. The policy also calls for the implementation of an internal EMS. We have developed, implemented, and continuously improved the EMS over the last twenty years. The EMS meets the EPA guidance for management systems and consists of policies, procedures, practices and guides that assign responsibility and help ensure compliance with environmental regulations.

State Environmental and Renewable Energy/Portfolio Standards

In 2019, Colorado legislation was signed that requires the AQCC to develop rules to reduce statewide greenhouse gas emissions 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, relative to 2005 emissions. As part of the settlement agreement related to our 2020 Electric Resource Plan that became effective in April 2022, we have agreed to reduce the greenhouse gas emissions related to our wholesale electricity sales in Colorado as follows: at least 26 percent in 2025, 36 percent in 2026, 46 percent in 2027, and 80 percent in 2030, with respect to the verified 2005 baseline. See "— POWER SUPPLY RESOURCES – Resource Planning" regarding our 2020 and 2023 Electric Resource Plan.

In 2019, New Mexico legislation was signed that amended the RPS that required our New Mexico Utility Members to obtain 10 percent of their energy requirements from renewable sources in 2020 and thereafter. The legislation added requirements for our New Mexico Utility Members to obtain 40 percent renewable energy by 2025 and 50 percent renewable energy by 2030 and adds a target of achieving a zero carbon resource standard by 2050 with at least 80 percent renewable energy. The legislation includes regulatory relief for the 2050 target if implementing the provisions of the bill are not technically feasible, hamper reliability or increase cost of electricity to unaffordable levels.

The existing Colorado RES requires our Colorado Utility Members to obtain 10 percent (or 20 percent from Colorado Utility Members that serve 100,000 or more meters) in 2020 and thereafter of their energy requirements from renewable sources and requires we provide to our Colorado Utility Members at least 20 percent in 2020 and thereafter of the energy at wholesale from renewable resources. The Colorado law permits us to count renewable sources utilized by our Colorado Utility Members for their RES requirement towards compliance with our separate RES requirement.

We currently provide sufficient energy from renewable sources to meet our Utility Members' current obligations under the RPS or RES requirements in New Mexico and Colorado, as applicable, and expect to be able to continue meeting our Utility Members' RPS/RES obligations in 2024 to the extent a Utility Member does not meet its obligation with renewable generation owned or controlled by such Utility Member as permitted under our wholesale electric service contract. We expect to be able to achieve compliance with our separate RES that requires 20 percent of the energy we provide to our Colorado Utility Members at wholesale to come from renewable sources in 2024.

The impacts of the 2019 Colorado and New Mexico legislation and our compliance with the settlement agreement related to our 2020 Electric Resource Plan, and our 2023 Electric Resource Plan, could include modifications to the design or operation of existing facilities, increases in our operating expenses and potential stranded costs, investments in new generation and transmission facilities, the closure of additional generating facilities, the closure of individual coal-fired generating facilities earlier than scheduled, and other impacts additional to the closures of coal-fired generating facilities.

Air Quality

The Clean Air Act. Pursuant to the Clean Air Act, the EPA has adopted standards regulating the emission of air pollutants from generating facilities and other types of air emission sources, establishing national air quality standards for major pollutants, and requiring permitting of both new and existing sources of air pollution. The Clean Air Act requires that the EPA periodically review, and revise if necessary, its adopted emission standards and national ambient air quality standards. Both of these actions can impose additional emission control and compliance requirements, increasing capital and operating costs.

Among the provisions of the Clean Air Act that affect our operations are (1) the acid rain program, which requires nationwide reductions of SO_2 and NO_X from existing and new fossil fuel-based generating facilities, (2) provisions related to major sources of toxic or hazardous pollutants, (3) New Source Review, which includes requirements for new plants that are major sources and modifications to existing major source plants, (4) National Ambient Air Quality Standards that establish ambient limits for criteria pollutants, and (5) requirements to address visibility impacts from regional haze. Many of the existing and proposed regulations under the Clean Air Act impact coal-fired generating facilities to a greater extent than other sources.

Our facilities are currently equipped with pollution controls that limit emissions of SO_2, NO_X, and particulates below the requirements of the Clean Air Act and our permits. As needed, some specified units have appropriate mercury emission controls. We have pollution control equipment on each of our generating facilities. All three units at Craig Station have scrubbers to remove SO_2, baghouses for particulate removal and low NO_X burners. Craig Station Unit 2 has selective catalytic reduction equipment for NO_X control. Craig Station Unit 3 has selective non-catalytic reduction equipment for NO_X control and an activated carbon injection system to control mercury emissions. Springerville Unit 3 has scrubbers to remove SO_2, a baghouse for particulate removal, low NO_X burners and selective catalytic reduction equipment for NO_X control, and an activated carbon injection system for controlling mercury emissions.

Basin, as the operator for the Laramie River Generating Station, is responsible for environmental compliance and reporting for that facility. TEP is the operator of Springerville Unit 3 and is responsible for environmental compliance of that station. Springerville Unit 3 operates under a Title V air operating permit that was issued for all Springerville Generating Station units. Springerville Unit 3 was designed and constructed to comply with permitted Best Available Control Technology emission standards. If liabilities arise as a result of a failure of environmental compliance at Laramie River Generating Station or Springerville Unit 3, our respective responsibility for those liabilities is governed by the operating agreements for the facilities.

We own and operate combustion turbine generating facilities that burn natural gas and/or fuel oil at four locations in Colorado and one in New Mexico. The combustion turbines are subject to emission limits lower than those of coal-fired generating facilities. All units have the necessary air and water permits in place and are operated in accordance with regulatory provisions. Steam turbine facilities include steam injection to control NO_X emissions by lowering thermal NO_X formation.

Acid Rain Program. The acid rain program requires nationwide reductions of SO_2 and NO_X emissions by reducing allowable emission rates and by allocating emission allowances to generating facilities for SO_2 emissions based on historical or calculated levels, and reducing allowable NO_X emission rates. We receive and hold sufficient SO_2 allowances for compliance with the acid rain program.

Greenhouse Gas Regulation. In October 2015, the EPA initiated rulemaking to control the emissions of CO_2 from new and existing electric generating units referred to as the "Clean Power Plan." In 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending judicial review. In 2019, the EPA repealed the Clean Power Plan and replaced it with the Affordable Clean Energy rule. Legal actions were filed in opposition to and support of the Affordable Clean Energy rule, and in January 2021, the D.C. Circuit Court of Appeals issued an opinion vacating both the Affordable Clean Energy rule and the repeal of the Clean Power Plan. In September 2022, the EPA opened a pre-proposal public docket about greenhouse gas regulations for fossil fuel-fired power plants. We submitted comments in December 2022. The Biden administration proposed a new rulemaking in May 2023 to establish emission guidelines for existing coal-fired generating facilities and larger natural gas-fired facilities. In the proposed rule, the EPA determined that the best system of emission reduction was carbon capture and storage for the coal-fired facilities and that natural gas-fired facilities could utilize either carbon capture and storage or cofire units with 96 percent hydrogen and that these requirements would be phased in between 2030 and 2040. The EPA's proposed rule is not yet finalized. Once finalized, states will need to develop plans to implement the final rule for existing facilities. State plans may be more stringent than the federal rule. We cannot predict what the EPA will include in its final rule, nor can we predict what individual states will require in plans to implement the final rule for existing sources. We will work with the individual states in which we operate and attempt to make any state plan as manageable as possible.

Mercury and other Hazardous Air Pollutants. The Clean Air Act also provides for a comprehensive program for the control of hazardous air pollutants, including mercury. The EPA must treat mercury as a "hazardous air pollutant" subject to a requirement to install MACT on new and existing units. In 2012, the EPA finalized a MACT rulemaking with emissions standards across four categories of emissions. We are in compliance with the rule's emission limits at our generating facilities and have the appropriate emission controls. In April 2023, the EPA proposed a revision to the Mercury and Air Toxics Standards regulation. In the proposed rule, the EPA signaled its intent to lower the emission standard for particulate matter and to require the use of particulate matter continuous emission monitors at coal-fired facilities. If finalized as proposed, the final rule would impact each of our coal-fired units, except for Craig Station Unit 1. The EPA's proposed rule is not yet final and we cannot predict what the final rule will include at this time.

In June 2022, Public Protections from Toxic Air Contaminants Act was signed into Colorado law. The law requires larger stationary air pollution sources in Colorado, including electric generating facilities, to report facility-wide emissions of toxic air contaminants. The first report is due by June 30, 2024. The State of Colorado has developed a list of toxic air contaminants that includes well over 400 compounds that, if emitted, must be reported to the state. The law also requires that Colorado identify up to five toxic air contaminants by April 30, 2025, that may pose a risk of harm to public health and propose health-based standards by April 30, 2026. Until the health-based standards are developed and implemented, we cannot predict what the impact may be on our operations.

New Source Review. Section 114(a) Information Requests related to New Source Review Program Requirements. Over the past two decades, the U.S. Department of Justice, on behalf of the EPA, has brought enforcement actions against owners of coal-fired facilities alleging violations of the New Source Review provisions of the Clean Air Act in cases where emissions increased without commensurate installation or upgrades of pollution controls. Such enforcement actions were brought against facilities after review by the EPA of operations and maintenance records of the facilities. The EPA has the authority to review such records pursuant to Section 114 of the Clean Air Act. To date, we have not been issued an information request for EPA review of the records of any of our facilities, and therefore, are not involved in any enforcement action from past operational and maintenance activities.

National Ambient Air Quality Standards. In October 2015, the EPA lowered the NAAQS for ozone from 75 ppb to 70 ppb. The J.M. Shafer Generating Station and Knutson Generating Station are located in the DM/NFR ozone nonattainment area. The DM/NFR ozone nonattainment area did not meet the 2008 ozone NAAQS of 75 ppb and this area is not anticipated to meet the 2015 ozone NAAQS that was set at 70 ppb. In 2019, the EPA reclassified the DM/NFR ozone nonattainment area from “moderate” to “serious” nonattainment for the 2008 ozone NAAQS of 75 ppb. The DM/NFR ozone nonattainment area again failed to meet the 2008 ozone NAAQS and the State of Colorado and the EPA redesignated the area from "serious" to "severe" nonattainment in 2022. At the same time, the DM/NFR also failed to attain the 2015 ozone NAAQS (70 ppb) and the State of Colorado and the EPA redesignated the area from "marginal" to "moderate" nonattainment. The DM/NFR ozone nonattainment area developed a plan to comply with the 2008 and 2015 ozone NAAQS; however, the plan does not demonstrate compliance by 2023 as required, but shows compliance by 2026. Additional redesignations to more stringent nonattainment status are expected. The EPA is now in its regular recurring five year process of reevaluating the efficacy of the ozone standard(s) and is working to determine if the national standard for ozone is adequate to protect public health and the environment. Implementation of a lower ozone standard will require the evaluation of additional emission controls for many major sources in the DM/NFR nonattainment area. In the 2022 plan development effort, additional emission controls were not required at the J.M. Shafer Generating Station and the Knutson Generating Station, but could be required under future redesignation evaluations.

Transport Rule/Good Neighbor Plan. In 2022, the EPA proposed a rule that would implement a Federal Implementation Plan to assure that states identified in the proposal would not significantly contribute to violations of air quality standards in downwind states that are working to attain or maintain the 2015 8-hour ozone NAAQS. The proposed rule would require significant NO_X emission reductions across 26 states, including Wyoming, at coal-fired electric generation units, including Laramie River Generating Station. The EPA finalized the proposed rule in March 2023 and excluded Wyoming from the program. In the final rule, the EPA signaled that it planned to include Arizona in the program after it reassessed the modeling for the state. In February 2024, the EPA proposed a new rule to include Arizona in the program. We are assessing the proposal to determine if Springerville Unit 3 would be subject to more stringent emission limitations; comments on the proposal are due May 16, 2024. It is anticipated that the EPA would issue a final rule regarding the inclusion of Arizona in the fourth quarter of 2024 or the first quarter of 2025. Several states have challenged the final rule and others have filed petitions with the courts to stay the effectiveness of the proposed rule until the resolution of the legal challenges. It is uncertain when any new requirements, if finalized, would take effect, or if the final rule will be upheld.

Regional Haze. In June 2005, the EPA issued the Clean Air Visibility Rule, amending its 1999 Regional Haze Rule, which had established timelines for states to improve visibility in national parks and wilderness areas throughout the U.S. Under the amended rule, states were required to evaluate certain types of older sources and based on the outcome of the evaluation require them to install best available retrofit technology. States were also required to establish Reasonable Progress Goals in SIPs to meet a 2064 goal of natural visibility conditions. The Regional Haze program is intended to be implemented through a series of ten-year plans developed by states and approved by the EPA. States were required to submit a second ten year plan in 2018, however, the EPA adjusted the submittal timeline to 2021. The amended Regional Haze Rule could require additional controls for particulate matter, SO_2 and NO_X emissions from utility sources.

Colorado adopted a regional haze plan that does not require additional emission controls on Craig Station and incorporates retirement dates for Craig Station Units 1, 2, and 3. Colorado submitted its plan to the EPA and it is still under review. Arizona adopted a plan that required additional emission reductions at Springerville Unit 3 but no new emission controls. Wyoming adopted a plan that did not require any further emission controls or any lower emission limits. In Arizona, Springerville Unit 3 commenced operation in 2006 and has state-of-the-art emission controls for SO_2, NO_X and particulate matter. In Wyoming, Laramie River Generating Station installed selective catalytic reduction on Unit 1 and selective non-catalytic reduction on Units 2 and 3 during the previous regional haze period. Arizona and Wyoming have submitted their plans to EPA and are awaiting the conclusion of the EPA's review and approval/disapproval process. It is possible that additional emission controls and/or compliance emission limits could be proposed as part of the EPA approval process in these states.

Water Quality

The Clean Water Act. The Clean Water Act regulates the discharge of process wastewater and certain storm water to WOTUS under the NPDES permit program. Colorado has been delegated NPDES permitting authority by the EPA and is therefore our primary water quality regulator in Colorado. Each of our generating facilities presently has the appropriate permits. Water quality regulations require us to comply with each state's water quality standards, including sampling and monitoring of the waters around affected plants. Construction projects disturbing greater than 1 acre of land require construction stormwater general permits. We, or our contractor, regularly seek, obtain, and comply with these permits for our varied construction projects. Section 404 of the Clean Water Act requires permits to authorize the placement of dredged or fill material (e.g., soil and rock) into waterways and wetlands. This permit program is primarily administered by the Corps and we regularly rely on various Corps general permits for construction projects.

The regulatory definition of WOTUS under the Clean Water Act and other federal statutes has been in a state of flux for the past two decades due to U.S. Supreme Court decisions, and multiple sequential rulemaking efforts of the Corps and the EPA spanning the past three presidential administrations. In May 2023, the U.S. Supreme Court in *Sackett v EPA* found that federal jurisdiction over WOTUS only extends to "relatively permanent waters" and wetlands that directly abut/touch WOTUS. This decision substantially reduced federal Clean Water Act jurisdiction and the Corps and the EPA promptly revised their regulations to conform with the *Sackett* decision. The reduction in federal jurisdiction has increased state attention to this topic. Some states in our service territory are moving towards state regulatory programs to protect waterways no longer under federal jurisdiction. We are monitoring these state proceedings in both legislative and regulatory settings and expect further state action in 2024, particularly in Colorado. Many of our construction activities in WOTUS are authorized by streamlined federal general permits. We anticipate needing fewer of these federal permits in the future due to the *Sackett* decision but recognize that we may see an increased future need for yet to-be-established state permits and approvals. Our facilities are generally located in arid and semi-arid regions where WOTUS and state waters are less numerous and of smaller size compared to wetter regions of the U.S. We have employed compliance methods that shield us from the uncertainty of fluctuating WOTUS definitions.

Spill Prevention Control and Countermeasures. The EPA issued regulations governing the development of Spill Prevention Control and Countermeasures plans. Some of our substation and generation sites are subject to these regulations and all Spill Prevention Control and Countermeasures plans meet the regulations.

Other Environmental Matters

Coal Ash. We manage coal combustion by-products such as fly ash, bottom ash and scrubber sludge by removing excess water and placing the by-products in land-based units in a dry form. At Craig Station, the combustion by-products are used for mine land reclamation at the adjacent coal mine. The mine-fill and landfills are regulated by state environmental agencies and all required permits are in place. We are meeting all compliance obligations under the final Coal Combustion Residual rule.

Global Climate Change Regulatory Developments Outside the Clean Air Act. Consideration of laws and regulations to limit emissions of greenhouse gases is underway at the international, national, regional and state levels. International negotiations will determine what, if any, specific commitments to reduce greenhouse gas emissions will be made by all countries that are party to the United Nations Framework Convention on Climate Change, including the U.S. The outcome of the 28th Conference of the Parties held by the United Nations in Dubai during December 2023 is a broad international agreement based on non-binding commitments with no enforcement provisions; therefore, the agreement will not directly dictate any particular emission reduction obligations for U.S. businesses. Commitments are subject to review every five years under the agreement.

Colorado and New Mexico have each adopted separate sets of requirements for the reduction of CO_2 emissions from fossil fuel-fired generating facility. The RPS or RES adopted by each state are further discussed above. In recent years, Colorado adopted specific greenhouse gas emission reduction targets for the electric utility industry and economy wide targets. The Colorado legislature is planning to consider additional emission reduction targets for electric utilities in its 2024 legislative session. These new targets could require additional emission controls or the retirement of additional existing fossil fueled generating facilities, the building of additional renewable generation resources and the construction of new transmission facilities.

The Comprehensive Environmental Response, Compensation and Liability Act. CERCLA (also known as Superfund) requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties liable for the release to take or pay for such actions. Potentially responsible parties are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to a site. To our knowledge, we are not currently subject to liability for any Superfund matters. However, we generate certain wastes, including hazardous wastes, and send certain of our wastes to third party waste disposal sites. As a result, there can be no assurance that we will not incur liability under CERCLA in the future.

Toxic Substances Control Act/Polychlorinated Biphenyls. We have limited quantities of PCBs in transmission equipment in the existing system. As oils are changed and systems replaced, PCBs are eliminated and PCB-free oils are used, reducing regulatory risk.

Per- and polyfluoroalkyl substances. There has been much recent federal and state activity surrounding a class of synthetic compounds known collectively as PFAS. This activity has occurred in both water and waste contexts. We are monitoring ongoing regulatory and policy matters regarding PFAS and has taken steps to replace PFAS-containing fire suppression systems at our generating facilities with non-PFAS alternatives. Given the evolving regulatory environment and the widespread nature of PFAS in society and the environment, we continue to evaluate the relevance and extent of this topic to our operations.

Endangered Species Act. Compliance with the ESA can affect the cost and timing of our various activities including operation of existing generation and transmission facilities, and planning and permitting new or expanded facilities. The ESA can apply to us indirectly because it obligates federal agencies that are taking some form of permit, right-of-way, funding, or other action that we need. We regularly need federal permits and approvals from various agencies. The ESA also applies to us directly when our activities have potential to "incidentally take" an ESA-listed species and there is no associated federal action. In February 2024, we enrolled in one program related the lesser prairie-chicken and applied to another related to the monarch butterfly that provide incidental take coverage for our activities.

Environmental groups frequently petition the USFWS to protect additional species and challenge regulatory and species listing decisions. The outcomes of ESA litigation results in a dynamic regulatory environment. The USFWS manages future species listings via the National Listing Workplan, which was updated in April 2023. We monitor the workplan for upcoming species listings that might affect our operations and plans. In particular, we are monitoring several species with workplan timing estimates in the next few years such as: little brown bat, western bumble bee, Suckley’s cuckoo bumble bee, and monarch butterfly. It is difficult to predict if and how these potential future species listings might affect our operations because the USFWS may decline to list certain species or may list species with regulatory provisions or guidance that reduces or eliminates restrictions on our activities.

ITEM 1A. RISK FACTORS

Our business, financial condition or results of operations could be materially adversely affected by various risks, including those described below.

Members and Regulatory Risks

Utility Member disputes and uncertainty regarding Utility Member withdrawals, including, but not limited to, the final outcome of the contract termination payment amount, may materially impact our financial condition, results of operations, long-term system resource planning, our long-term debt, our liquidity and our access to capital.

Pursuant to our Bylaws, a Member may 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 October 2021, FERC accepted our Board approved modified contract termination payment methodology, subject to refund. In December 2023, FERC issued an order on our contract termination payment methodology. In January 2024, we, United Power, and others parties filed requests for rehearing with FERC. See "BUSINESS — MEMBERS – Contract Termination Payment and Relationship with Members."

In April 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. See "BUSINESS — MEMBERS – Contract Termination Payment and Relationship with Members." While these three Utility Members have provided notices to withdraw, there is no certainty that they will be able to pay the contract termination payment required upon withdrawal or will actually withdraw as they have asserted. This uncertainty makes long-term system resource planning difficult and makes it more expensive to plan and operate our business.

In addition, Basin has filed a complaint against us related to NRPPD's notice to withdraw from us and claims we have breached our contract with Basin and seeks a preliminary injunction that would restrict NRPPD's withdrawal from us. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

Although we view our calculation of United Power's contract termination payment based upon FERC's December 2023 order will not require us to offer prepayment of certain of our long-term debt, the contract termination payment methodology proceeding is on-going. United Power has requested rehearing of FERC's December 2023 order and has filed protests with FERC disagreeing with our calculation of United Power's contract termination payment. In additional our lenders may not agree that our calculation of United Power's contract termination payment does not require us to offer a prepayment of certain of our long-term debt.

If United Power prevails in its rehearing request or its challenges to our calculation of the contract termination payment and United Power or another Utility Member withdraws, it may materially impact us. If FERC's contract termination payment methodology underestimates the monetary value of a Utility Member's obligation or a significant number of our Utility Members withdraw, it may materially impact us. If Basin is successful in its claims for breach of contract or in obtaining an injunction, it may materially impact us. If negative conclusions about our financial condition, results of operations, long-term system resource planning and our long-term debt are drawn from FERC's December 2023 order or any subsequent FERC orders on the contract termination payment, it may materially impact us. If FERC subsequently revises the contract termination payment methodology that requires low payments by withdrawing Utility Members, it could cause a Material Adverse Effect (as defined in our 2022 Revolving Credit Agreement). This, in turn, could materially impact us.

The material impacts of some or all of the above items occurring could include a significant increase in rates to our remaining Utility Members, additional Utility Member unrest and desires to withdraw from our Utility Members, a new lawsuit from NRPPD related to the injunction sought by Basin, an inability to meet the DSR of at least 1.10 in our Master Indenture that would require us to take corrective action, a materially adverse effect on our financial condition and results of operations including our liquidity, an inability to issue additional secured debt under our Master Indenture, a material hindrance in our long-term system resource planning, credit ratings downgrades, and we may be required to offer a prepayment of certain of our long-term debt. In addition, an offer of prepayment or prepayment of certain of our long-term debt could be viewed by lenders as an event of default under the cross-default provision of certain of our loan agreements, including our 2022 Revolving Credit Agreement that provides backup for our commercial paper program. If such debt is accelerated due to the cross-default provision and we are unable to pay such accelerated debt, our lenders could assert that there is an event of default under our Master Indenture.

As we are subject to rate regulation by FERC, our ability to raise our wholesale rates to our Utility Members is limited and challenges to or a delay in implementing our formula rate filing in 2023 could have an adverse effect on our results of operations and financial condition.

Wholesale rate changes for our Utility Members must be approved by a majority of our Board and is also subject to FERC approval or acceptance. FERC accepted our existing Class A wholesale rate structure (A-40) to our Utility Members as a “stated rate.” 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 until the date a new Class A wholesale rate schedule goes into effect. In June 2023, we filed with FERC a 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. Although we expect that FERC will accept, subject to refund, our Class A formula rate, FERC has yet to issue an order on our formula rate. See "BUSINESS — RATE REGULATION." Because of the delay in FERC’s order, we are currently recovering costs below budget for 2024. Our A-41 formula rate included a 6.3 percent rate increase. In addition, it is not certain if FERC’s order on our A-41 formula will accept an effective date of January 1, 2024, as we requested, or a later date. A later effective date for our formula rate, may impact the period that we may true-up to actual costs. A continued delay in FERC’s acceptance of our A-41 formula rate and an effective date other than January 1, 2024 may adversely affect our results of operations, financial position and cash flow.

Because we expect FERC to accept, subject to refund, our A-41 formula rate, we have reversed the $44.9 million of environmental obligation expense that was originally recognized in 2022 as a regulatory item because we believe recovery of these incurred costs is probable. If FERC does not accept our formula rate or rejects us creating a regulatory item for this environmental obligation expense, we may need to re-expense this amount. If FERC rejects our formula rate or we are required to re-expense this amount, it may adversely affect our results of operations and financial position.

In addition, our ability to create a regulatory asset or the utilization of regulatory liabilities in the future, including those associated with the early retirements of our generating facilities to implement our preferred IRA scenario as part of Phase I 2023 ERP, requires FERC approval. If we are unable to obtain FERC approval, the cost of electric service we provide to our Utility Members could increase and, as a result, could affect their ability to perform their contractual obligations to us. In addition, we may experience additional Utility Member unrest and desires to withdraw from our Utility Members.

In addition to FERC's jurisdiction over our wholesale rates to our Utility Members, FERC also regulates our market-based rate authority and our transmission service rates. With the anticipated withdrawal of United Power and the addition of new renewable resources, our market-based rate authority in the WACM balancing authority area may be impacted. If we no longer have market-based rate authority in certain balancing authority areas, it could have an adverse effect on our results of operations and financial condition. If FERC were to require a reduction in our transmission service rates, it could have an adverse effect on our results of operations and financial condition.

Resource planning and COPUC oversight, including regulatory requirements, may impact our financial condition and future plans, and our proposed resource plan is contingent on receipt of federal funding.

In Colorado, we are required to file and obtain COPUC approval for our Electric Resource Plan. In December 2023, we filed our Phase I 2023 ERP that included our preferred IRA scenario that assumed we will receive federal funding under the New Era Program. The COPUC may condition, modify, or reject our preferred plan, which may impact our future plans and financial condition. See "BUSINESS — POWER SUPPLY RESOURCES – Resource Planning." If we are unable to obtain federal funding under the New Era Program as contemplated by our preferred plan, it may increase the costs of our preferred plan, including the costs of new resources and costs related to our stranded assets, or result in modification of our preferred plan. All of this may impact our financial condition and future plans and may result in continued or additional Utility Member unrest.

Other states in which we operate may also implement laws or regulations that require us to also file resource plans in their state. Multiple state resource plan requirements may lead to additional costs to comply with unique requirements and impact our future plans.

The perceived competitiveness of our wholesale rates by our Utility Members and limitations on Utility Members' self-supply options could result in continued and additional Utility Member unrest.

Our wholesale electric service contract requires each Utility Member to purchase and receive from us at least 95 percent of the power required for the operation of the Utility Member's system. Each Utility Member may elect to provide up to 5 percent of its requirements from distributed or renewable generation owned or controlled by the Utility Member. While the price and volatility for wholesale electricity has increased substantially in the past couple years, the perceived competitiveness of our wholesale rates and the limitations on Utility Member's self-supply options by our Utility Members may result in continued Utility Member unrest.

One of the important elements of our Responsible Energy Plan is increased Utility Member flexibility, and we continue to discuss with our Utility Members the structure of partial requirements options. See "BUSINESS — MEMBERS." The delayed implementation of increased Member Utility flexibility caused by challenges in proceedings at FERC and FERC's orders contributed to LPEA's November 2023 complaint against us that includes claims related to partial requirements options. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

If we are unsuccessful in keeping our wholesale rates to our Utility Members competitive or implementing increased flexibility for our Utility Members, we may experience continued and additional Utility Member unrest and desires to withdraw, unfavorable media coverage, credit ratings downgrades, additional laws and regulations targeted at us, or other negative consequences which may impact our financial condition and future plans.

Increased competition could reduce demand for our electric sales.

The electric utility industry has experienced increasing wholesale competition, enabled by deregulation and revisions to existing regulatory policies, competing energy suppliers, including third party energy remarketing companies, new technology, and other factors. Competing energy suppliers are targeting our Utility Members by claiming to be able to offer lower priced and cleaner wholesale electric power. This includes assisting our former and existing Utility Members in seeking to withdraw from membership in us and financing the withdrawal payment by our Utility Members. On the retail side, states in which our Utility Members' service territories are located do not have retail competition legislation. However, these states could enact retail competition legislation which could reduce our electricity demand from our Utility Members and the pool from which we recover fixed costs, resulting in higher rates to our Utility Members. Competing energy suppliers are also targeting the communities and tribes our Utility Members serve by claiming to be able to offer lower priced and cleaner wholesale electric power. It also includes assisting the communities and tribes our Utility Members serve by helping them create electric utilities or seek new power suppliers. In addition, federal legislation could mandate retail choice in every state.

We and our Utility Members are subject to regulations issued by FERC pursuant to PURPA with respect to matters involving the purchase of electricity from, and the sale of electricity to, qualifying facilities and co-generators. An increase in the number and/or size of qualifying facilities selling electricity to our Utility Members could reduce our electricity demand from our Utility Members.

We may face competition from qualifying facilities, other utilities, competing energy suppliers, and fuel sources, or as a result of technological innovations. Technological innovations may include methods or products that allow consumers to bypass the electric supplier, to switch fuels or to reduce consumption. These innovations may include, but are not limited to, demand response, distributed generation, energy storage and microgrids. Competition from other utilities and competing energy suppliers may consist of competition from other electric companies, helping our Utility Members withdraw from membership in us, annexations by municipalities, helping municipalities and tribes our Utility Members serve create electric utilities, and competition for the sale of excess power to non-members on both a short-term and long-term basis. If competition increases, additional Utility Members may withdraw, rates to our remaining Utility Members may increase or our financial condition and results of operations could be adversely affected.

Our Utility Members have a substantial number of industrial and large commercial customers who could decrease operations, shut down, or elect to self-generate in the future.

Based on the information available to us by our Utility Members, which is 2022 data in most cases and not independently verified by us, industrial and large commercial customers account for approximately 34 percent of our Utility Members' energy sales. A large percentage of these sales are in energy production, extraction and transportation. The 15 largest customers of our Utility Members, a substantial percentage of which are in energy production, extraction and transportation, total approximately 14 percent of the aggregate retail electric energy sales of our Utility Members, based on the same data from our Utility Members. High inflation and rising interest rates, an economic downturn, volatile energy and fuel prices, increased demand for renewable energy, additional government restrictions imposed on extractive industries, or other changes in business conditions could affect the level of energy sales to our Utility Members' large commercial customers. Future sales to large commercial customers could decrease should these large commercial customers decide to decrease their operations, shut down operations, or elect to self-generate. In addition, weather has a significant impact on the affect the amount of energy sales to our Utility Members' irrigation customers. Wetter weather results in less use of irrigation, driving decreased energy sales.

Our financial condition is largely dependent upon our Utility Members.

Our financial condition is largely dependent upon our Utility Members satisfying their obligations under their wholesale electric service contracts with us. In 2023, 86.2 percent of our revenues from electric sales were from our Utility Members. We do not control the operations of our Members, and their financial condition is not tied to our results of operations. Accordingly, we are exposed to the risk that one or more of our Utility Members could default in the performance of their obligations to us under their wholesale electric service contract. A default could result from financial difficulties of one or more Utility Members or because of intentional actions by our Utility Members. Our results of operations and financial condition could be adversely affected if a significant portion of our Utility Members default on their obligations to us, and such Utility Members' defaults could trigger an event of default under certain of our loan agreements.

Our cooperative business model is facing increasing challenges.

As a member-owned cooperative, we are facing increasing challenges to our cooperative business model. There are increasing challenges to our governance structure, the long-term nature of our wholesale electric service contracts, limitations in our wholesale electric service contracts in the amount of self-supply provided to our Utility Members, and our transition to a cleaner generation portfolio. We are also facing increasing regulatory oversight and the prospect of future laws and regulations that could change our governance structure and cooperative business model. If we are not able to address or mitigate these challenges, we may experience additional laws and regulations targeted at us, additional Utility Member unrest and desires to withdraw, credit ratings downgrades, unfavorable media coverage or other negative consequences which may impact our financial condition and future plans.

We may be held liable for the actions or omissions of our Members, despite the fact that we and our Members are separate legal entities and we do not own, operate, control or have the right to control our Members.

Litigation seeking to impose liability on us for the actions of our Utility Members have occurred. The plaintiffs in these actions have claimed that we are jointly liable for the actions of our Utility Members, including under theories of partnership, joint venture, joint/common enterprise, or alter ego. Although a jury determined in one case that we and one of our Utility Members do not operate as a joint venture or joint enterprise, there can be no assurance that a court or jury will determine in the future that we are not severally or jointly liable for the actions of our Members. Our results of operations and financial condition could be adversely affected if courts or juries determine we are severally or jointly liable for the actions of our Members.

Environmental Risks

Compliance with existing and future environmental laws and regulations, including RPS/RES, may increase our costs of operation and further affect the utilization of current generation facilities, and satisfying asset retirement and environmental reclamation obligations are significant.

As with most electric utilities, we are subject to extensive federal, state and local environmental requirements that regulate, among other things, air emissions, water discharges, land use, and the use and management of hazardous and solid wastes. Compliance requires significant expenditures for the installation, maintenance and operation of pollution control equipment, monitoring systems and other equipment or facilities, including the settlement of asset retirement obligations and expenses for environmental reclamation obligations. Furthermore, it is expected for existing environmental regulations to become increasingly stringent at both the federal and state level and for us to be subject to new legislation or regulation, including those related to greenhouse gas emissions or renewable or clean energy standards. The Biden administration has stated it has a goal to achieve a carbon pollution-free power sector by 2035 and to put the U.S. on a path to a net-zero economy by 2050.

The existing and any additional federal, state or local environmental restrictions imposed on our operations, including RPS/RES requirements imposed on us or our Utility Members and greenhouse gas reduction requirements on us, could result in significant additional costs, including capital expenditures. Implementation of regulations or more stringent standards may require us to modify the design or operation of existing facilities or purchase emission allowances. In addition, implementation of regulations on existing legislation or more stringent standards or costs could further affect generating facilities retirement and replacement decisions, including the shutting down of additional generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled, and may substantially increase the cost of electricity to our Utility Members. In 2023, our existing generating facilities generated approximately 48.2 percent of our energy available for sale, a substantial percentage of which is generated by coal-fired generating facilities. The cost impact of the implementation of regulation from existing legislation and future legislation will depend upon the specific requirements thereof and cannot be determined at this time, but could be significant, including increases in our operating expenses and potential stranded costs and investments in new generation and transmission. See "BUSINESS — ENVIRONMENTAL REGULATIONS" for additional information regarding environmental regulations.

The cost estimates for asset retirement and environmental reclamation obligations are based upon information using various assumptions related to closure, post-closure and operating costs, the timing of future cash outlays, inflation and discount rates, and the potential compliance method. We continue to evaluate these obligations and make adjustment to these costs as needed.

Litigation relating to environmental issues, including claims of property damage or personal injury caused by greenhouse gas emissions, has increased generally throughout the U.S. Likewise, actions by private citizen groups to enforce environmental laws and regulations are becoming increasingly prevalent.

There can be no assurance that we will always be in compliance with all environmental requirements or that we will not be subject to future or additional RPS/RES requirements or regulations related to greenhouse gas emissions. Failure to comply with existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could cause the complete, temporary or permanent shutdown of individual generating units not in compliance with these regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disasters and resource depletion impacts.

Climate change can create physical and financial risks. Physical risks include changes in weather conditions and an increase in extreme weather events. The energy needs of our Utility Members’ customers vary with weather. To the extent weather conditions are affected by climate change, such customers’ energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in new generation and transmission. Decreased energy use due to weather changes may result in decreased revenues.

Climate change may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of greenhouse gas emissions, could impact the availability of goods and the prices charged by our suppliers that would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of greenhouse gas emissions as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions, including cost of capital. To the extent insurance markets view climate change and emissions of greenhouse gases as an insurance risk or elect not to insure generation facilities that have greenhouse gas emissions, it could negatively affect our ability to obtain insurance or cause us to obtain insurance with higher deductibles, higher premiums, lower insurable amounts, or more restrictive policy terms.

Our Utility Members' service territories are exposed to extreme weather, including high winds, thunderstorms, blizzards, drought, flooding, ice storms, and tornados. These severe weather events can physically damage our facilities and our Utility Members' facilities. Any such occurrence both disrupts the ability to deliver energy and increases costs. Extreme weather can also reduce usage and demand for energy of our Utility Members' customers and could result in us incurring obligations to third parties related to such events. These factors could negatively impact our results of operations, financial condition and cash flow.

To the extent the frequency of extreme weather events increases, this could increase our cost of providing service to our Utility Members. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions in the western part of the U.S., especially in the southwest U.S., may continue to impact the water levels at reservoirs used by WAPA to supply us hydroelectric-based power and may result in further reduction in the amount of capacity and energy allocated from WAPA, which may be material, and may further increase the cost of such to us. This could require us to purchase power to serve our Utility Members and/or reduce our ability to sell excess power on the wholesale market and reduce revenues. Drought conditions or actions taken by the court system, regulators, or legislators could also limit our supply of water, which could adversely impact operations of our generating facilities, cause early retirement of generating facilities and increase the cost for energy. Drought conditions also contribute to the increase in wildfire risk from our facilities. While we carry liability insurance, given an extreme event, if we are found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition and cash flow.

Operating Risks

We are subject to increasing supply chain risk that could impact the timing of construction and the cost of additional facilities and the operation of our existing facilities.

A significant disruption in the global supply chain for the procurement and delivery of equipment for the construction of additional facilities, including transmission facilities, and operation of our existing facilities, along with workforce availability and inflation, could impact the timing and costs of the construction and operation of our facilities. Continued or increased disruptions could cause us to seek alternative supply at potentially higher costs and supply shortages may not be fully resolved, which could impact our ability to construct additional facilities and delivery power to our Utility Members, which could have an adverse effect on future revenues and costs, which could be material. In addition, supply chain issues could require us to operate other generating facilities at higher cost or pay significantly higher prices to obtain electric power from other sources, which could have an adverse effect on our results of operations.

Early retirements of our existing generating facilities may impact reliability for our Utility Member*s.*

The early retirement of our former and existing generating facilities, including Craig Station and Springerville Unit 3, may impact our ability to deliver reliable electric power to our Utility Members. Early closure of existing generating facilities will result in us having less excess capacity, will make us more reliant upon our remaining dispatchable generating facilities and renewable resources, and we expect to construct an additional natural gas-fired dispatchable generating facility and energy storage resources. As we continue our transition to a cleaner generation portfolio with the addition of more intermittent renewable resources, we may have increased reliability risk especially during extreme weather events that may impact the supply of natural gas to our natural gas-fired generating facilities, the operation of our transmission system and the delivery of electric power to our Utility Members.

Increased reliability risk could have the effect of increasing the cost of electric service we provide to our Utility Members and have an adverse effect on our results of operations. In addition, we may experience additional Utility Member unrest and desires to withdraw from our Utility Members.

We may experience transmission constraints or limitations to transmission access, and our ability to construct, and the cost of, additional transmission is uncertain.

We currently experience periodic constraints on our transmission system and those of other utilities used to transmit energy from our remote generators due to periodic maintenance activities, equipment failures and other system conditions. We manage these constraints using alternative generation dispatch and energy purchasing patterns. The long-term solution for reducing transmission constraints can include joining a regional transmission organization, purchasing additional wheeling service from other utilities, or construction of additional transmission lines which would require significant capital expenditures.

As part of our Responsible Energy Plan, we are increasing our renewable portfolio, and as other utilities are also increasing their renewable portfolios, the addition of renewable resources is increasing the demand for access to existing transmission lines, making it difficult for us to acquire transmission capacity, and we expect it will be necessary for us to construct or pay for additional transmission lines. Although we are participating in the expansion of SPP's service territory from the Eastern Interconnection into the Western Interconnection, to be completed in early 2026, there is no certainty this expansion will occur on time or that the SPP market will improve the transmission constraints or limitations to transmission access.

In most cases, construction of transmission lines presents numerous challenges. Environmental and state and local permitting and siting processes may result in significant inefficiencies and delays in construction. The timing needed to acquire land rights may also be lengthy. These issues are unavoidable and are addressed through long-term planning. We typically begin planning new transmission at least 10 years in advance of the need and voluntarily participate in regional and interregional transmission planning and cost allocation discussions with neighboring transmission providers. In the event that we are unable to complete construction of planned transmission expansion, we may be unable to implement aspects of our Responsible Energy Plan or preferred IRA scenario as part of our Phase I 2023 ERP, and we may need to rely on purchases of market-priced electric power, which could put increased pressure on electric rates. We may also experience continued or additional Utility Member unrest.

We could be adversely affected if we or third parties are unable to successfully operate our facilities.

Our performance depends on the successful operation of our facilities. Operating facilities involves many risks, including, among others:

- operator error and breakdown or failure of long lead-time equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- problems resulting from an aging workforce and retirements;
- the ability to maintain and retain a knowledgeable workforce;
- work slowdown or stoppages due to communicable diseases or other factors;
- availability and cost of equipment and fuel;
- supply chain interruptions, including transportation interruptions;
- availability and cost of water;
- water supply interruptions;
- extreme weather events, including high or low temperatures, severe thunderstorms, drought, and wildfires;
- catastrophic events, such as fires, earthquakes, explosions, floods or other similar occurrences; and
- compliance with mandatory reliability standards when such standards are adopted and subsequently revised.

Unforeseen outages at our generating facilities or transmission facilities could lead to higher costs because we may be required to purchase power in volatile electric power markets. With the closures of our generating facilities and planned closure of additional generating facilities, the unforeseen outages of one or more of our remaining generating facilities may have a greater impact on us and lead to service outages and business interruptions, which could negatively impact our business and operations. A decrease or elimination of revenues from electric power produced by our generating facilities or an increase in the cost of operating the facilities could adversely affect our results of operation.

We are exposed to uncertainty in connection with construction projects at new and existing generating facilities, third party generating facilities related to our long-term power purchase contracts, and new and existing transmission facilities, and in connection with decommissioning of certain existing facilities.

Our existing facilities require ongoing capital expenditures in order to maintain efficient and reliable operations. Many of our generating facilities were constructed over 30 years ago and, as a result, may require significant capital expenditures to maintain efficiency and reliability and to comply with changing environmental requirements. In March 2024, we expect to execute engineering, procurement and construction contracts for two solar-based facilities totaling 255 MWs that are expected to achieve commercial operation in 2025. Based upon our preferred IRA scenario as part of our Phase I 2023 ERP, we expect to construct a new natural gas-fired generating facility and new energy storage resources. We also upgrade and build new transmission facilities to maintain reliability, for load growth, or for the accommodation of new generation. In the years 2024 through 2028, we estimate that we may invest approximately $2.4 billion in new generation and transmission facilities and upgrades to our existing transmission facilities.

We have three solar-based power purchase contracts totaling 340 MWs for facilities that are being constructed by third parties and expected to achieve commercial operation in 2024.

The completion of construction projects is subject to substantial risks, including delays or cost overruns due to:

- shortages and inconsistent quality of equipment, materials and labor;
- siting, permits, approvals and other regulatory matters;
- unforeseen engineering problems;

- work slowdown or stoppages due to communicable diseases or other factors;
- environmental, cultural and geological conditions;
- environmental litigation;
- delays or increased costs to interconnect our facilities with transmission grids;
- increased costs due to inflation;
- governmental regulations and investigations, including the investigation regarding solar panels;
- unanticipated increases in cost of materials and labor and supply chain interruptions; and
- performance by engineering, construction or procurement contractors.

An important financial aspect of constructing our new owned renewable and energy storage resources, including the two solar-based facilities totaling 255 MWs that are expected to achieve commercial operation in 2025, is us receiving either investment tax credits or production tax credits, along with direct pay as provided in the Inflation Reduction Act. If we do not qualify for all or some of the credits or direct pay either due to late construction or failure to comply with the requirements to obtain such, it is expected to negatively impact the economics of these projects and increase the cost of electric service we provide to our Utility Members.

The early retirement and decommissioning of certain of our existing generating facilities, including Craig Station and Springerville Unit 3, and the Colowyo Mine is subject to substantial risks. In addition, the early retirement and decommissioning of additional existing generating facilities and the Colowyo Mine before the end of their useful life is subject to substantial risks, including potential requirements to recognize a material impairment of our assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning, reclamation and cancellation of long-term contracts for such generating plants and facilities. The closure of Springerville Unit 3 is also subject to the risk of obtaining agreements with the applicable parties and with reasonable terms. Closure of any of such generating facilities may force us to incur higher costs for replacement capacity and energy, will make us more reliant upon our remaining generating facilities, and cause us to have less excess capacity. The decommissioning costs may exceed our estimate, which could negatively impact our results of operations and liquidity. Furthermore, our ability to create a regulatory asset to defer expenses associated with these early retirements or the utilization of regulatory liabilities requires FERC approval.

All of these risks could have the effect of increasing the cost of electric service we provide to our Utility Members and, as a result, could affect their ability to perform their contractual obligations to us. In addition, we may experience additional Utility Member unrest and desires to withdraw from our Utility Members.

We rely on purchases of electric power from other power suppliers and long-term agreements to purchase and transport fuels and to sell electricity we generate, which exposes us to market and counterparty risks.

Our electric power supply strategy relies, in part, on purchases of electric power from other power suppliers. In 2023, purchased power provided 51.8 percent of our energy requirements. Based upon our preferred IRA scenario as part of our Phase I 2023 ERP, we expect to enter into additional renewable power purchase contracts. These purchases consist of a combination of purchases under long-term agreements and short-term market purchases of electric power. We also rely on long-term agreements with third parties to (a) manage our supply and transportation of fuel for our generating facilities, and (b) sell electricity we generate to non-member utilities. We are exposed to the risk that counterparties to these long-term agreements will breach their obligations to us or claim that we are in breach. We are exposed to the risk that bidders to our requests for new resources will not honor their bids. requiring us to use an alternative bid or restart the process. We are also exposed to the risk that counterparties to our renewable power purchase contracts and engineering, procurement, and construction contracts will be unable to construct the renewable generating facilities by the time specified in the respective contract or at all. If this occurs, we may be forced to enter into alternative contractual arrangements or enter into short-term market transactions at then-current market prices. Purchasing electric power in the market exposes us, and consequently our Utility Members, to market price risk because electric power prices can fluctuate substantially over short periods of time. The terms of these new arrangements may be less favorable than the terms of our current agreements, which could have an adverse effect on our results of operations.

When we enter into long-term power purchase contracts, we rely on models based on our judgments and assumptions of factors such as future demand for electric power, future market prices of electric power and the future price of commodities used to generate electricity. These judgments and assumptions may prove to be incorrect. As a result, we may be obligated to purchase electric power under long-term agreements at a price which is higher than we could have obtained in alternative short-term arrangements. Conversely, our reliance on short-term market purchases exposes us to increases in electric power prices.

Our long-term power purchase contracts include contracts with WAPA and Basin, consisting of 12.6 percent and 13.7 percent, respectively, of our Utility Member energy sales in 2023 (in MWhs). We experience favorable pricing terms under our WAPA contracts under federal laws that give preference to federal hydropower production to "preference" customers, including cooperatives. If the federal laws under which we receive favorable pricing were to be amended or eliminated, if WAPA were to no longer provide us with power or favorable pricing for any other reason, or we were required to assign some or all of our power from WAPA to a third party, we would have to pay significantly higher prices to obtain this electric power, which could have an adverse effect on our results of operations and our ability to implement aspects of our Responsible Energy Plan. The prices we pay for power under the WAPA and Basin contracts are determined by WAPA and Basin, respectively, and are subject to change in accordance with the terms of the contracts and certain FERC approval. If we would have to pay significantly higher prices under these contracts, it could have an adverse effect on our results of operations.

Volatile natural gas prices could have an adverse effect on the operation of our facilities and our cost of electric service.

The wholesale electricity price generally correlates with the wholesale natural gas price in most regions of the U.S. Generally, low gas prices correlate to low wholesale electricity prices and could thereby reduce the competitiveness of our coal-fired generating facilities. Low natural gas prices could negatively impact the economics of operating our coal-fired generating facilities, which could cause the temporary or permanent shutdown of individual coal-fired generating facilities, including the shutting down of individual coal-fired generating facilities earlier than scheduled, thereby significantly increasing the cost of electric service we provide to our Utility Members and affecting their ability to perform their contractual obligations to us. High natural gas prices could increase the cost of operating our natural gas-fired generating facilities and the price of short-term market purchases and energy imbalance charges from other utilities, thereby significantly increasing the cost of electric service we provide to our Utility Members and affecting their ability to perform their contractual obligations to us.

Losses from wildfires could adversely affect our financial condition, future results of operations, and cash flow.

We have ownership or capacity interests in approximately 5,827 miles of transmission lines, including transmission lines that cross through forest areas and grasslands. Certain of our transmission facilities are located on federal land and certain permits with the federal government impose strict liability on us up to a maximum cap related to our transmission facilities. If a wildfire involving our transmission facilities were to occur, we could be liable for property damage, costs of fire-fighting activities, and other costs, for which liability could be substantial and in excess of our liability insurance. In addition, the availability of liability insurance may decrease, and the insurance that we are able to obtain may have higher deductibles, higher premiums, lower insurable amounts, or more restrictive policy terms. Any such liability could materially affect us and our financial condition, future results of operations, and cash flow.

We may not be able to obtain an adequate supply of fuel, which could limit our ability to operate our facilities.

We obtain our fuel supplies, including coal, natural gas and oil, from a number of different suppliers, including mines that we own. Any disruptions in our fuel supplies, including disruptions due to weather, rail transportation, labor relations, communicable diseases, permitting, regulatory matters, environmental regulations, or other factors affecting our coal mines or fuel suppliers, could result in us having insufficient levels of fuel supplies. For example, various rail transportation issues in the past have caused transportation companies to be unable to perform their contractual obligations to deliver coal on a timely basis and in the past have resulted in lower than normal coal inventories at certain of our generating facilities that have resulted in reduced operations at such facilities. Inventory shortages could occur in the future due to any of the disruptions described above. Natural gas and oil supplies can also be subject to disruption due to operational issues, natural disasters, extreme weather, and other events. Any failure to maintain an adequate inventory of fuel supplies could require us to operate other generating facilities at higher cost or pay significantly higher prices to obtain electric power from other sources, which could have an adverse effect on our results of operations.

Financing Risks

We have a substantial amount of indebtedness and we expect this amount to increase significantly.

As of December 31, 2023, we had total debt outstanding of approximately $3.1 billion, of which approximately $2.9 billion was secured under our Master Indenture. We have incurred indebtedness primarily to construct, acquire, or make capital improvements to generation and transmission facilities to supply the current and projected electricity requirements of our Utility Members and to meet our other long-term electricity supply obligations. Additionally, we expect to incur substantial indebtedness in the future, and we forecast that we will have approximately $3.8 billion of total debt outstanding in 2028. If demand for electricity from our Utility Members and under our long-term power sales agreements is materially less than projected, we might not generate sufficient revenue to meet the DSR and ECR requirements in our Master Indenture or to service our indebtedness. If this occurs, we may be required to raise our rates, revise our plans for capital expenditures and/or restructure our long-term commitments. These actions may adversely affect our operations, and we may be unable to generate sufficient additional revenue to pay our obligations. Further, failure to meet the ECR requirement in our Master Indenture or failure to service the indebtedness secured by our Master Indenture would result in an event of default under our Master Indenture and other loan agreements. Consequently, our results of operations, liquidity and financial condition could be adversely affected.

We expect to soon begin constructing, and expect we will need to construct or acquire, additional generation, including energy storage resources, such as batteries, and transmission facilities to meet our Utility Members' demands, to comply with new greenhouse gas reduction and RPS/RES legislation, and to implement our Responsible Energy Plan and our Electric Resource Plan, which may require substantial additional capital expenditures that will significantly increase our long-term debt, or for which we may not be able to obtain financing, and may result in development uncertainties for our business.

In the years 2024 through 2028, based upon our preferred IRA scenario as part of our Phase I 2023 ERP, we estimate that we may invest approximately $2.59 billion in new facilities and upgrades to our existing facilities. We expect to incur significant indebtedness in connection with this capital expenditure program. The specific projects we undertake and the amount of such investments are subject to uncertainties and may be influenced by many factors, including:

- the forecasted electric demand of our Utility Members, which is impacted by partial requirements and Utility Members' withdrawals;
- availability and cost of power purchase options;
- our membership in a regional transmission organization;
- federal funding under the New Era Program; and
- regulatory approvals and changes.

Any construction program would require substantial additional capital, requiring us to obtain financing resulting in a significant increase in the amount of our long-term debt. A significant increase in long-term debt may increase the cost of the electric service we provide to our Utility Members. Failure to obtain financing may adversely affect our results of operations, liquidity and financial condition.

Our ability to access short-term and long-term capital and our cost of capital could be adversely affected by various factors, including credit ratings and current market conditions, and significant constraints on our access to capital could adversely affect our financial condition and future results of operations.

We rely on access to short-term and long-term capital for construction of new facilities and upgrades to our existing facilities, and as a significant source of liquidity for capital expenditures not satisfied by cash flow generated from operations. In the years 2024 through 2028, based upon our preferred IRA scenario as part of our Phase I 2023 ERP, we estimate that we may invest approximately $2.59 billion in new facilities and upgrades to our existing facilities which we expect will require us to take on significant additional long-term debt.

Our access to capital could be adversely affected by various factors, and certain market disruptions could constrain, at least temporarily, our ability to maintain sufficient liquidity and access capital on favorable terms, or at all. These factors and disruptions specific to us include:

- our credit ratings being downgraded;
- financial markets view of our relationship with our Utility Members and the withdrawal of Utility Members, including FERC's and a court's order on the contract termination payment methodology;
- challenges or delays related to wholesale rate changes for our Utility Members;
- our wholesale electric service contracts with our Utility Members only extending through 2050 that may limit the length of future financings; and

- financial markets' view of our clean energy transition and the timing and progress of such transition.

Other factors and disruptions that may impact our access to capital include:

- market conditions generally;
- economic downturn or recession;
- instability in the financial markets;
- market pressures, including tightening of lending standards, and/or internal bank balance sheet constraints that could prevent and/or lower our lenders' commitments to financings;
- the overall health of the energy industry and the generation and transmission cooperative sector;
- negative events in the energy industry, such as a bankruptcy of an unrelated energy company;
- war or threat of war; and
- cyberattacks, terrorist attacks or threatened attacks on our facilities or the facilities of unrelated energy companies.

If our ability to access capital becomes significantly constrained for any of the reasons stated above or any other reason, our ability to finance ongoing capital expenditures required to maintain existing facilities and to construct future facilities could be limited, our interest costs could increase and our financial condition and results of operations could be adversely affected.

We are exposed to market risks including economic downturns or recessions and instability in the financial markets, which could lead to changes in interest rates and availability of capital in credit markets. The interest rates on future borrowings could be significantly higher than interest rates on our existing debt. As of December 31, 2023, we had $761.1 million of debt with variable rates. The rates on this debt could increase.

We maintain the 2022 Revolving Credit Agreement which provides backup for our commercial paper program. The facility includes a letter of credit sublimit and a commercial paper backup sublimit, and financial covenants for DSR and ECR requirements consistent with the covenants in our Master Indenture. Failure to maintain these financial covenants or other covenants could preclude us from issuing commercial paper or from issuing letters of credit or from borrowing under the 2022 Revolving Credit Agreement.

We must make long-term decisions involving substantial capital expenditures based on current projections of future conditions.

Our decisions to meet our Utility Members' load demands by construction of new generation, including energy storage resources (such as batteries) and transmission facilities, by entering into long-term power purchase contracts, or by relying on short-term power purchase markets are based on long-term forecasts. We rely on our forecasts to predict factors affecting our Utility Members' load demands such as economic conditions, population increases and actions by others in the development of generation and transmission facilities. Even though forecasts are less reliable the farther into the future they extend, we must make decisions based on forecasts that extend decades into the future due to the long-term nature of power purchase contracts, the long lead time necessary to develop and construct new facilities, and the long-term expected useful life of those facilities.

In April 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. These three Utility Members represent 22.1 percent of our Utility Member sales in 2023. See "BUSINESS — MEMBERS – Contract Termination Payment and Relationship with Members." While these three Utility Members have provided notices to withdraw, there is no certainty that they will actually withdraw as they have asserted. This uncertainty makes long-term forecasting difficult. Additional Utility Members may also seek to withdraw.

Our Board has established a partial requirements option. While six Utility Members have previously elected this partial requirements option, we and our Utility Members continue to evaluate the structure for implementing partial requirements options that may be re-filed with FERC. There is no certainty that they will be able to implement this option and the terms of this option. This uncertainty makes long-term forecasting difficult.

Our forecasts and actual events may vary significantly, and, as a result, we may rely on technology that becomes less competitive, install transmission facilities in areas where they are not needed, or we may not develop the appropriate number or type of generating facilities. If we over-estimate the growth in our Utility Members' demand or Utility Members' partial requirements or withdrawal, there is no assurance that the price of surplus power or energy from surplus resources would be economical or could be sold without a loss. If we underestimate the growth in our Utility Members' demand or Utility Members' partial requirements or withdrawal, we may be required to purchase power or energy at a cost substantially above the cost we would have incurred to obtain the power or generate the energy from owned facilities.

We are subject to risks associated with our ability to obtain adequate insurance at acceptable costs.

The financial condition of some insurance companies, actual or threatened physical attacks or cyberattacks, natural disasters, wildfire losses, and views on climate change and emissions of greenhouse gases, among other things, could have disruptive effects on insurance markets. The availability of insurance may decrease or be completely unavailable, and the insurance that we or the operators of our facilities are able to obtain may have higher deductibles, higher premiums, lower insurable amounts, or more restrictive policy terms. These issues could be viewed by lenders as triggering an event of default under certain provisions of certain of our loan agreements if a waiver or amendment cannot be obtained. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect our results of operations, financial condition and cash flow.

General Risks

Cybersecurity threats are increasing and if we are unable to protect our information systems, our operations could be disrupted and our financial condition could be adversely affected.

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure. We rely on networks, information systems and other technology, including the Internet and third party hosted servers, to support a variety of business processes and activities. We use information systems to process financial information and results of operations for internal reporting purposes and to comply with regulatory financial reporting, legal and tax requirements. We own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run our facilities are not completely isolated from external networks. Our generation and transmission assets and information technology systems, or those of our jointly owned plants, could be directly or indirectly affected by deliberate or unintentional cyber incidents. There appears to be an increasing level of activity, sophistication, and maturity of threat actors, in particular nation state actors, that wish to disrupt the U.S. bulk power system. Such parties could view our computer systems, software, or networks as attractive targets for cyberattack. For example, malware has been designed to target software that runs the nation's critical infrastructure such as power transmission grids. These incidents may be caused by failures during routine operations such as system upgrades or user errors, as well as network or hardware failures, malicious or disruptive software, computer hackers, rogue employees or contractors, cyberattacks by criminal groups or activist organizations, ransomware, geopolitical events, natural disasters, failures or impairments of telecommunications networks, or other catastrophic events. In addition, such incidents could result in unauthorized disclosure of material confidential information, including personally identifiable information.

In addition, in the ordinary course of business, we collect and retain sensitive information, including personally identifiable information about employees, directors, and other third parties, and other confidential information. In some cases, administration of certain functions are outsourced to third-party service providers that could also be targets of cyberattacks.

If our technology systems are breached or otherwise fail, we may be unable to fulfill critical business functions, including the operation of our generation and transmission assets, our ability to collect revenue, and our ability to effectively maintain certain internal controls over financial reporting. Further, our generation assets rely on an integrated transmission system, a disruption of which could negatively impact our ability to deliver power to our Utility Members. Our collection of revenue from our Utility Members relies upon our Utility Members' ability to collect revenue from their customers, a disruption of which or cybersecurity attack on our Utility Members could negatively impact us. Our Utility Members have their own independent cybersecurity programs and procedures. A major cyber incident could result in significant business disruption, compromised or improper disclosure of data, and expenses to repair security breaches or system damage and could lead to litigation, regulatory action, including penalties or fines, and an adverse effect on our financial condition, results of operations, and reputation. Moreover, the amount and scope of insurance maintained against losses resulting from any such cyber incident may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. In addition, as cybercriminals become more sophisticated, the cost of proactive defensive measures may increase. We also may have future compliance obligations related to new mandatory and enforceable NERC reliability standards addressing the impacts of geomagnetic disturbances and other physical security risks to the reliable operation of the bulk power system.

Failure to attract and retain a qualified workforce could have an adverse effect on our business.

Our business is dependent on our ability to attract, train, and retain employees representing diverse backgrounds, experiences, and skill sets. The competition for talent has become increasingly intense and we may experience increased employee turnover due to this tightening labor market and challenges to attract a qualified workforce, especially with specialized knowledge. Specialized knowledge is required of our technical employees for construction and operation of facilities. This may pose additional difficulty for us as we work to recruit, retain, and motivate employees in this climate, while maintaining a diverse and inclusive work environment that enables all our employees to thrive. Failure to hire and adequately train and retain employees, including the transfer of significant historical knowledge and expertise to new employees, or future availability and cost of contract labor, may adversely affect our results of operations, financial position and cash flow.

We may be subject to physical attacks.

As operators of energy infrastructure, we are facing heightened risk of physical attacks on our electric systems. Our generation and transmission assets and systems are geographically dispersed and are often in rural or sparsely populated areas which make them especially difficult to adequately detect, defend from, and respond to such attacks. Recent physical attacks on other electric utilities in the U.S. and the coverage of such attacks by the media has further increased this risk and the risk of copycat attacks.

If, despite our security measures, a significant physical attack occurred, we could have our operations disrupted, property damaged, experience loss of revenues, response costs, and other financial loss; and be subject to increased regulation, litigation, and damage to our reputation, any of which could have a negative impact on our business and results of operations.

We also may have future compliance obligations related to new mandatory and enforceable NERC reliability standards addressing physical security risks for our transmission assets. These standards may require significant expenditures for the installation, maintenance and operation of monitoring systems and other equipment or facilities.

A portion of our workforce is represented by unions. Failure to successfully negotiate collective bargaining agreements, strikes or work stoppages could cause our business to suffer.

Many of our employees are covered by collective bargaining agreements, and other employees may seek to be covered by collective bargaining agreements. Our current collective bargaining agreements expire in April 2026. Strikes, work stoppages or other business interruptions could occur if we are unable to renew these agreements on satisfactory terms, enter into new agreements on satisfactory terms or otherwise manage changes in, or that affect, our workforce, which could adversely impact our business, financial condition and results of operations. The terms and conditions of renegotiated or new collective bargaining agreements could also increase our costs or otherwise affect our ability to fully implement future operational changes to enhance our efficiency or to adapt to changing business needs or strategy.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

We have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our data and systems. We are also subject to mandatory cybersecurity regulatory requirements. Our risk management programs, which address both enterprise and energy commodity risks, provides for evaluating and addressing cybersecurity risks and cybersecurity compliance. As part of our evaluation of cybersecurity risks, we consider cybersecurity risks and threats related to use of third-party service providers. Depending on the third-party service provider, the services provided by such third party and the data stored or to which such third party has access, we require different cybersecurity protections and specific cybersecurity programs that the third party must maintain. Our Utility Members have their own independent cybersecurity programs and procedures.

Cybersecurity risks with long-term resolutions are evaluated and added to our risk register, which is reviewed and updated by a corporate committee quarterly. This corporate committee, consisting of senior executives and support staff, meets regularly to assess enterprise, including cybersecurity, and energy commodity risks. Our Chief Administrative Officer/CHRO manages our information technology department and has executive oversight of our cybersecurity program. Our Chief

Information Officer and Chief Information Security Officer that report directly or indirectly to our Chief Administrative Officer/CHRO are responsible for implementation of our cybersecurity program. Our Chief Information Officer and Chief Information Security Officer have multiple cyber-related certifications from nationally recognized organizations and a combined experience in cybersecurity of 30 years.

We interface regularly with a wide range of external organizations and participate in classified briefings to maintain an awareness of current cybersecurity threats and vulnerabilities. We utilize third-party consultants to evaluate and test our cybersecurity preparedness and participate in national transmission grid security exercises that also address cybersecurity threats. Our security efforts are intended to address evolving and changing cyber threats. We operate a dedicated cyber security center with capabilities to monitor, detect, analyze, mitigate, and respond to cyber threats.

The Engineering and Operations Committee of our Board has oversight of our cybersecurity program and the risks from cybersecurity threats. The Engineering and Operations Committee is briefed quarterly with both oral and written reports on cybersecurity including cybersecurity risks. Our Board receives oral briefing on cybersecurity including cybersecurity risks no less than once per year and our Board is provided access to all written reports provided to the Engineering and Operations Committee.

We are subject to numerous cybersecurity threats and the cybercriminals are becoming more sophisticated and are increasingly targeting electric utilities. A major cyber incident could result in significant business disruption, compromised or improper disclosure of data, and expenses to repair security breaches or system damage and could lead to litigation, regulatory action, including penalties or fines, and an adverse effect on our financial condition, results of operations, and reputation. See "RISK FACTORS – General Risks" for additional information. While there have been immaterial incidents of phishing and attempted financial fraud across our system, there has been no material impact on business or operations from these attacks. However, we cannot guarantee that security efforts will prevent breaches, operational incidents, or other breakdowns of information technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future.

ITEM 2. PROPERTIES

Generating Facilities

We own, lease or have undivided percentage interests in various generating facilities which are identified in the table below. All of our interests in these facilities or agreements, as applicable, are subject to the lien of our Master Indenture.

Name	Location	% Interest Owned or Leased	Fuel Used	Unit Rating (MW)*	Our Share (MW)*	Year Installed
Coal						
Craig Generating Station Unit 1	Colorado	24.0	Coal	427	102	1980
Craig Generating Station Unit 2	Colorado	24.0	Coal	410	98	1979
Craig Generating Station Unit 3	Colorado	100.0	Coal	448	448	1984
Laramie River Generating Station Unit 1	Wyoming	28.5	Coal	560	—	1980
Laramie River Generating Station Unit 2	Wyoming	28.5	Coal	570	241	1981
Laramie River Generating Station Unit 3	Wyoming	28.5	Coal	570	241	1982
Springerville Generating Station Unit 3	Arizona	100.0	Coal	419	419	2006
Gas/Oil						
Burlington Generating Station	Colorado	100.0	Oil	110	110	1977
J.M. Shafer Generating Station	Colorado	100.0	Gas	272	272	1994
Knutson Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Limon Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Pyramid Generating Station	New Mexico	100.0	Gas/Oil	160	160	2003

* The Unit Ratings and our share for each generating facility are subject to fluctuations to account for various operating conditions and environmental mitigation equipment requirements.

Craig Generating Station. Craig Station is a three-unit, 1,285 MW coal-fired electric generating facility located near Craig, Colorado. Craig Station Units 1 and 2 and related common facilities are known as the Yampa Project and jointly owned as tenants in common by us and four other regional utilities pursuant to a participation agreement. We own a 24 percent interest in Craig Station Units 1 and 2, which each have a capacity of 427 MWs and 410 MWs, respectively, and a 100 percent interest in Craig Station Unit 3, which has a capacity of 448 MWs. We are the operating agent for all three units and are responsible for the daily management, administration and maintenance of the facility. The costs associated with operating Craig Station Units 1 and 2 are divided on a pro-rata basis among all the participants. Our total share of Craig Station's capacity is 648 MWs. On September 1, 2016, we announced that the owners of Craig Station Unit 1 reached an agreement whereby Unit 1 is intended to be retired by December 31, 2025. We and the other joint owners of Craig Station Unit 2 intend to retire Craig Station Unit 2 by September 30, 2028. Based upon our preferred IRA scenario as part of our Phase I 2023 ERP, we intended to retire Craig Station Unit 3 by January 1, 2028.

Laramie River Generating Station. Laramie River Generating Station is a three-unit, 1,700 MW coal-fired electric generating facility located near Wheatland, Wyoming and operated by Basin. Laramie River Generating Station and related transmission lines are known as the MBPP and are jointly owned as tenants in common by us and three other regional utilities pursuant to a participation agreement. We own a 28.5 percent interest in the total capacity of the facility. Certain costs associated with operating the facility are divided on a pro-rata basis among the participants, while other costs are shared in proportion to the generation scheduled and energy produced for each participant. Laramie River Generating Station Unit 1 is connected to the Eastern Interconnection, while Units 2 and 3 are connected to the Western Interconnection. Our share of Laramie River Generating Station's total capacity is 482 MWs, which we receive out of Units 2 and 3.

Springerville Generating Station Unit 3. Springerville Unit 3, located in east-central Arizona, is a 419 MW unit that is part of a four-unit, 1,578 MW coal-fired electric generating facility operated by TEP. Under contractual agreements, we, as the lessee of Springerville Unit 3, are taking 419 MWs of capacity from the unit and selling 100 MWs of such capacity to Salt River Project. We own a 51 percent equity interest (including the 1 percent general partner equity interest) in Springerville Partnership, which owns Springerville Unit 3. Our leasehold interest, as the lessee of Springerville Unit 3, is subject to the lien of our Master Indenture, but Springerville Unit 3 is not subject to the lien of our Master Indenture. Springerville Unit 3 is subject to a mortgage and lien to secure the Springerville certificates. Based upon our preferred IRA scenario as part of our

Phase I 2023 ERP and subject to receipt of New ERA Program funding related to Springerville Unit 3 and reaching agreements with the applicable parties, we intended to retire Springerville Unit 3 by September 15, 2031.

Burlington Generating Station. Burlington Generating Station consists of two 55 MW simple-cycle combustion turbines that operate on fuel oil and is located in Burlington, Colorado. The units are primarily operated during periods of peak demand. Burlington Generating Station is wholly owned and operated by us.

J.M. Shafer Generating Station. J.M. Shafer Generating Station is a 272 MW, natural gas-fired, combined-cycle generating facility located near Fort Lupton, Colorado, which is primarily operated to provide intermediate load generating capacity.

Knutson Generating Station. Knutson Generating Station consists of two 70 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Brighton, Colorado. The units are primarily operated during periods of peak demand. Knutson Generating Station is wholly owned and operated by us. Both units are under contract with a third party under a tolling arrangement starting May 1, 2024 through December 2027, which is an arrangement whereby the purchaser provides its own natural gas for generation of electricity.

Limon Generating Station. Limon Generating Station consists of two 70 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Limon, Colorado. The units are primarily operated during periods of peak demand. Limon Generating Station is wholly owned and operated by us.

Pyramid Generating Station. Pyramid Generating Station consists of four 40 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Lordsburg, New Mexico. The units are primarily operated during periods of peak demand. Pyramid Generating Station is wholly owned and operated by us.

Transmission

As of December 31, 2023, we own, lease, or have undivided percentage interest in transmission lines as described in the following table (estimated miles based on Geographic Information System):

Voltage (kV)	Miles
69	56
115	3,300
138	173
230	1,198
345	1,100
Total	5,827

We are an ownership participant in the MBPP (Laramie River Generating Station) and Yampa Project (Craig Station Units 1 and 2) transmission systems and have ownership interests or capacity rights in several other transmission line participation projects. Transmission investment also includes ownership or major equipment ownership in 422 substations and switchyards. All our interests in these facilities or agreements, as applicable, are subject to the lien of our Master Indenture.

Coal Mines

We, through our wholly owned subsidiary Colowyo Coal, own the Colowyo Mine, which is a surface mine located near Craig, Colorado. The Colowyo Mine is our only mine that we own that has active mining operations. In January 2020, we announced that our Board approved the early retirement of the Colowyo Mine. The Colowyo Mine is expected to cease coal production by 2030, at which time operations would turn entirely to reclamation.

We, through our wholly owned subsidiary Elk Ridge, also own the New Horizon Mine, which is located near Nucla, Colorado. The New Horizon Mine is in post-reclamation monitoring and no longer produces coal.

ITEM 3. LEGAL PROCEEDINGS

Information required by this Item is contained in "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8.

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 annual report on Form 10-K.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Not Applicable.

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

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

We are owned entirely by our forty-five 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-two 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-eight 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 are regulated as a public utility under Part II of the FPA.

We supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or long-term purchase contracts with respect to various generating facilities. Our diverse generation portfolio provides us with maximum available power of 4,323 MWs, of which approximately 1,366 MWs comes from renewables.

In 2023, we sold 18.2 million MWhs, of which 90.7 percent was to Utility Members. Total revenue from electric sales was $1.4 billion for the year ended December 31, 2023, of which 86.2 percent was from Utility Member sales. Our results for the year ended December 31, 2023 were primarily impacted by cool and unusually wet weather conditions from May through August, lower power market prices, as well as lower availability from our coal-fired generating facilities which resulted in lower energy sales, lower rate stabilization measures and increased maintenance costs due to planned outages at our coal-fired generating facilities.

- Non-member electric sales decreased $18.1 million primarily due to lower long-term sales in 2023.
- Rate stabilization represents recognition of income 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 $47.1 million of previously deferred membership withdrawal income during 2023 compared to $95.6 million of previously deferred membership withdrawal income during 2022 as part of our rate stabilization measures.
- Production expense increased $13.7 million, or 7.7 percent, primarily due to higher maintenance costs at certain generating facilities resulting from maintenance outages at those facilities.
- Fuel expense decreased $70.2 million, or 21.3 percent, primarily due to lower generation from our coal-fired generating facilities. The lower generation resulted from maintenance outages and short-term market prices being below our generating costs, therefore, more power was purchased in the market. Additionally, the average rate for natural gas was 49.2 percent lower in 2023 compared to the same period in 2022.
- Coal mining expense increased $34.6 million primarily due to the acceleration of asset retirement obligation accretion related to the South Taylor pit beginning final reclamation at the end of December 2023, which resulted in additional reclamation expense of $31.2 million.
- Other operating expenses decreased primarily due to $44.9 million of New Horizon environmental obligation expense that was recorded in 2022 and reversed as a regulatory item in 2023 as part of our June 2023 Class A rate schedule (A-41) filing with FERC with a planned January 1, 2024 effective date, subject to FERC acceptance or approval.

Our Bylaws and 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 42 Utility Members extend through 2050. 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 December 31, 2023, 21 Utility Members have enrolled in this program with capacity totaling approximately 141 MWs of which 138 MWs are in operation. See "BUSINESS – MEMBERS" for a description of our wholesale electric service contract.

Pursuant to our wholesale electric service contracts with our Utility Members, we convened a contract committee starting in March 2024. Based upon the recommendation from our contract committee in 2019 and 2020, our Board approved a partial requirements option and a methodology to calculate a contract termination payment. We and our Utility Members continue to evaluate the structure of implementing partial requirements options that may be re-filed with FERC. See "BUSINESS – 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. 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 with FERC with the contract termination methodology based upon FERC's order. The revised rate schedule based upon FERC's adopted balance sheet approach uses our FERC financials and distinguishes between Utility Members served on the Western and Eastern Interconnection. The revised rate schedule includes requirements for a two-year notice and the payment of a contract termination payment. For further information see "BUSINESS – MEMBERS - Contract Termination Payment and Relationship with Members."

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. These three Utility Members comprised 22.1 percent of our Utility Member revenue and 18.2 percent of our operating revenue in 2023.

In July 2021, United Power's first amended complaint for declaratory judgement and damages against us and our Non-Utility Members was deemed filed alleging, among other things, that the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void and that we have breached our Bylaws and our wholesale electric service contract with United Power. Such litigation was dismissed in December 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. See "Note 14—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

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

Responsible Energy Plan

In July 2019, our Board established that we would pursue a transition to a cleaner energy portfolio by developing a Responsible Energy Plan. In January 2020, we released 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 sources;
- more local renewables for Utility Members through contract flexibility;
- promoting participation in a regional transmission organization; and
- expanding electric vehicle infrastructure and beneficial electrification.

For further information regarding our Responsible Energy Plan, see "BUSINESS – MEMBERS – Responsible Energy Plan."

Colorado Electric Resource Plan

In December 2023, we filed our Phase I 2023 ERP with the COPUC, which contained our 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 take advantage of direct pay of federal tax benefits for renewable and storage resources by increasing our owned resources. Our preferred plan retires Craig 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 identified in our January 2022 settlement agreement related to Phase I of our 2020 Electric Resource Plan. See "BUSINESS – POWER SUPPLY RESOURCES – Resource Planning."

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 our implementation of Responsible Energy Plan. In March 2024, we received an Invitation to Proceed from the U.S. Department of Agriculture to complete the full New ERA Program application. The New ERA Program implements the $9.7 billion funded in the Inflation Reduction Act of 2022.

Changing Environmental Regulations

We are subject to extensive federal, state and local environmental requirements. Furthermore, it is expected for existing environmental regulations to become increasingly stringent and for us to be subject to new legislation or regulation, including legislation or regulation relating to greenhouse gas emissions or renewable or clean energy standards.

At the federal level, the Biden administration has issued a series of executive orders focused on clean energy and climate change. The Biden administration has stated it has a goal to achieve a carbon pollution-free power sector by 2035 and to put the U.S. on a path to a net-zero economy by 2050.

At the state level, in 2019, the Colorado and New Mexico legislatures passed legislation related to climate change. In Colorado, the legislation requires the AQCC to develop rules to reduce statewide greenhouse gas emissions 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, relative to 2005 emissions. In New Mexico, the existing RPS was amended to require our New Mexico Utility Members to obtain 40 percent renewable energy by 2025 and 50 percent renewable energy by 2030 and adds a target of achieving a zero carbon resource standard by 2050, with at least 80 percent renewable energy. See "BUSINESS – ENVIRONMENTAL REGULATION" and "RISK FACTORS - Environmental Risks."

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. We consider the following accounting policies to be critical accounting policies due to the estimation involved or due to the particular significance they have on our consolidated financial statements.

Accounting for Rate Regulation. We are a rate-regulated entity and, as a result, are subject to the accounting requirements of Accounting for Regulated Operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board if it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from 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 Utility Members based on rates approved by the applicable authority. On September 3, 2019, we became a FERC jurisdictional public utility and our Board's rate setting authority, including the use of regulatory assets and liabilities, is now subject to FERC approval. Estimates of recovering 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 expenses concurrent with their recovery in rates.

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. Estimates of future expenditures for environmental reclamation obligations are not discounted.

Factors Affecting Results

Master Indenture

Our Master Indenture requires us to establish, subject to any necessary regulatory approvals, 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 historic and pro forma basis. Our DSR is calculated by dividing (x) our Net Margins Available for Debt Service (as defined in our Master Indenture), which is equal to our net margins for a period plus amounts deducted for the period to pay or make provision for interest on debt (including capitalized interest other than Allowance for Funds Used During Construction), lease expense, income tax expense, amortization of debt discount or premium, and depreciation and certain other non-cash items by (y) our Annual Debt Service Requirement (as defined in our Master Indenture), which is generally equal to the principal of, premium, if any, and interest (whether capitalized or expensed) on all of our debt and lease payments that become due in the applicable fiscal year or 12-month period at maturity or stated maturity, subject to special calculation rules applicable to specific types of debt (such as balloon debt). For purposes of the DSR calculation, we are permitted to exclude from the Annual Debt Service Requirement principal and interest on debt if the debt is paid or to be paid from defeasance obligations which have been irrevocably deposited or set aside in trust for payment of such debt. Our failure to achieve the required DSR is not a default under our Master Indenture as long as a plan is timely adopted and being implemented and no payment default has occurred. However, subject to certain limited exceptions, we cannot issue additional secured obligations under our Master Indenture unless the DSR for the prior fiscal year (or period of prior 12 consecutive months) is at least 1.10 and the estimated DSR for the current and next two years (or, if applicable, two years following the anticipated commercial operation date of the assets being financed) is at least 1.10. A DSR below 1.025 under our Master Indenture would require us to transfer all cash to a special fund managed by the trustee of our Master Indenture until our DSR is at least 1.025. We estimate that our DSR for the twelve months ended December 31, 2023 was 1.20.

Our Master Indenture also requires us to maintain an ECR at the end of each fiscal year of at least 18 percent. Our ECR equals our equity divided by the sum of our debt plus equity. Equity primarily consists of our aggregate net margins that we have not distributed in cash to our Members. Debt includes our indebtedness for borrowed money and capitalized leases but excludes indebtedness for which defeasance obligations (i.e., non-callable obligations of the U.S.) have been irrevocably deposited in trust. Our failure to maintain the ECR at the end of any given fiscal year would result in an event of default under our Master Indenture and restrict our ability to issue additional secured obligations under our Master Indenture. We estimate that as of December 31, 2023, our ECR was 24.0 percent.

As of December 31, 2023, we had approximately $2.9 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Pursuant to our Master Indenture, the DSR and ECR are calculated based on unconsolidated Tri-State financials and calculated in accordance with the system of accounts proscribed by FERC, not GAAP. The DSR and ECR calculated in accordance with FERC's system of accounts are not finalized and are subject to final adjustment.

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. To date, we have retired approximately $523.6 million of patronage capital to our Utility Members.

Pursuant to our previous Board Policy for Financial Goals and Capital Credits, we 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. This previous Board policy established a goal of our Board on an annual or quarterly basis to either defer revenues and incomes as a regulatory liability or recognize previously deferred revenues and incomes (as available) in an amount that will result in a DSR equal to a DSR goal for the applicable year as set forth in the policy. Our Board approved rates to our Utility Members for 2023 to achieve a DSR and ECR in excess of the requirements under our Master Indenture, including a DSR of 1.112 based on our 2023 budget. As allowed by our Bylaws, the deferral or recognition of previously deferred revenues and income is for the purpose of stabilizing margins and limiting rate increases from year to year. We recognized $47.1 million of previously deferred membership withdrawal income during 2023.

Our revised Board Policy for Financial Goals and Capital Credits, approved in connection with our Board's approval of our new Class A rate schedule (A-41) rate schedule, 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 management proposes rates that are expected to adequately recover our annual Utility Member revenue requirements contingent upon load projections and a budget approved annually by our Board.

Rates and Regulation

On September 3, 2019, we became FERC jurisdictional for our Utility Member 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 2 percent starting from March 1, 2021 until the first anniversary and 4 percent reduction (additional 2 percent reduction) on March 1, 2022 until the date a new Class A wholesale rate schedule goes into effect. See "BUSINESS – RATE REGULATION."

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 as a "stated rate." Our Class A rate schedule (A-40) was in effect for electric power sales to our Utility Members for 2023 through 2017. Our Class A rate schedule (A-40) consists of three billing components: an energy rate and two demand rates. Utility Member 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. On June 16, 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. In December 2023, FERC issued to us a deficiency letter with questions to answer. In January 2024, we filed answers to FERC's questions and again requested an effective date of our new rate schedule to be January 1, 2024. For further information on our formula rate see "BUSINESS – RATE REGULATION".

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. The amounts involved may be material.

Tax Status

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. We adopted the normalization method effective 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 payable that will be settled or received through future rate revenues. Pursuant to our new Class A rate schedule (A-41) filing with FERC, we will follow the flow-through method which will not have a material impact on our financial statements.

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 generally sold at market prices after consideration of incremental production costs. Demand billing 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 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 are dependent on maintaining an efficient supply chain. The procurement and delivery of materials and equipment have been impacted by the current domestic and global supply chain disruptions. We are experiencing shortages of critical items and longer lead-times on the procurement of certain materials and equipment, along with interruptions in production and shipping. Supply chain disruptions and inflation have 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.

Member Withdrawals

As described above, United Power, NRPPD, and MPEI provided us notices to withdraw from membership in us and terminate early their respective wholesale electric service contracts. United Power's and NRPPD's withdrawal effective date is May 1, 2024 and MPEI's withdrawal effective date is February 1, 2025. These three Utility Members comprised 22.1 percent of our Utility Member revenue and 18.2 percent of our operating revenue in 2023. As a condition of withdrawal, United Power, NRPPD, and MPEI are required to pay a contract termination payment amount and based upon our January 2024 revised rate schedule, the estimated contract termination payment amount is $709,482,596, $41,034,243, $77,933,263, respectively, prior to any reduction for allocated discounted patronage capital or regulatory liabilities credit, as applicable. If they elect a credit based on a discounted lump sum amount tied to their patronage capital in us, United Power, NRPPD, and MPEI's estimated contract termination payment amount after allocation of their respective estimated discounted lump sum patronage capital, based upon their balance as of December 31, 2022, is $627,630,197, $36,636,925, $63,218,757, respectively. United Power's estimated contract termination payment is the amount included in the unexecuted Withdrawal Agreement filed with FERC in January

2024. MPEI's estimated contract termination payment does not include its pro rata share of our power purchase obligations in the Western Interconnection or any reduction for regulatory liabilities credit. NRPPD's estimated contract termination payment does not include the price for facilities that NRPPD will purchase and will also be finalized when we receive additional information requested from third parties. Each of these Utility Members do not agree with our calculation of their estimated contract termination payment. These amounts are all subject to review and modification through proceedings currently pending with FERC.

Although there is no certainty that these Utility Members will pay the contract termination payment required upon withdrawal and withdraw as they have asserted, if these Utility Members pay and withdraw, it will significantly 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 payment, as calculated based upon our January 2024 revised rate schedule, to assist in mitigating the impacts of decreased Utility Members electric sales revenue. FERC stated in its December 2023 order that Utility Members "are unlikely to see a rate increase as a result of" FERC's adopted balance sheet approach. As part of our June 2023 formula rate filing with FERC, 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 in 2024 and 2025, we have entered into multiple power sales contracts with third parties for the sale of excess capacity and energy, with certain transactions starting May 1, 2024. Certain of these power sales contracts are contingent upon United Power's withdrawal on May 1, 2024. Our Phase I 2023 ERP also assumes these Utility Members will withdraw. However, there is a risk that FERC may not finally resolve all disputes related to the contract termination payment in a timely fashion or resolve them in a manner that fully mitigates the loss of Utility Member electric sales revenue.

See also "BUSINESS – MEMBERS - Contract Termination Payment and Relationship with Members" and "RISK FACTORS - Members and Regulatory Risks."

Year ended December 31, 2023 compared to year ended December 31, 2022

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 and coal sales revenue. 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 MWhs by type of purchaser for 2023 and 2022 (dollars in thousands):

	Year Ended December 31,		Period-to-Period Change	
	2023	2022	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 1,208,352	$ 1,213,234	$ (4,882)	(0.4)%
Non-member electric sales	145,228	163,355	(18,127)	(11.1)%
Rate stabilization	47,127	95,613	(48,486)	(50.7)%
Provision for rate refunds	94	(51)	145	(284.3)%
Other	66,615	61,420	5,195	8.5 %
Total operating revenues	$ 1,467,416	$ 1,533,571	$ (66,155)	(4.3)%
Energy sales (in MWh):				
Utility Member electric sales	16,530,385	16,525,315	5,070	— %
Non-member electric sales	1,694,116	2,077,532	(383,416)	(18.5)%
	18,224,501	18,602,847	(378,346)	(2.0)%

- Non-member electric sales revenue decreased primarily due to lower longer-term sales. Long-term sales decreased 397,684 MWhs, or 58.9 percent, to 277,623 MWhs in 2023 compared to 675,307 MWhs for the same period in 2022. The decrease in long-term sales was due to lower sales from Springerville Unit 3 to Salt River Project.

- Rate stabilization represents recognition of income from withdrawal of former Utility Members from membership in us that was previously deferred in accordance with accounting requirements related to regulated operations. In 2023, we recognized $47.1 million of previously deferred membership withdrawal income compared to $95.6 million of previously deferred membership withdrawal income during the same period in 2022. See "—Factors Affecting Results – Margins and Patronage Capital" for additional information.

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 2023 and 2022 (dollars in thousands):

	Year Ended December 31,		Period-to-Period Change	
	2023	2022	Amount	Percent
Operating expenses				
Purchased power	$ 404,876	$ 409,513	$ (4,637)	(1.1)%
Fuel	258,894	329,046	(70,152)	(21.3)%
Production	191,095	177,413	13,682	7.7 %
Transmission	187,874	175,889	11,985	6.8 %
General and administrative	88,621	79,640	8,981	11.3 %
Depreciation, amortization and depletion	171,460	184,047	(12,587)	(6.8)%
Coal mining	44,548	9,899	34,649	350.0 %
Other	(31,341)	53,509	(84,850)	(158.6)%
Total operating expenses	$ 1,316,027	$ 1,418,956	$ (102,929)	(7.3)%

- Fuel expense decreased primarily due to 1,912,371 MWh, or 20.7 percent, lower generation from our coal-fired generating facilities and a lower average rate for natural gas.

- Production expense increased primarily due to higher maintenance expenses as a result of scheduled maintenance outages at our generating facilities.

- General and administrative expense increased primarily due to lower recoveries of general and administrative costs from joint project activities and an increase in outside professional services.

- Depreciation, amortization and depletion expense decreased primarily due to lower amortization of regulatory assets as the regulatory asset related to the deferred Nucla impairment loss was fully amortized as of December 31, 2022.

- Coal mining expense increased primarily due to the acceleration of asset retirement obligation accretion related to the South Taylor pit beginning final reclamation at the end of December 2023.

- Other operating expenses decreased primarily due to $44.9 million of New Horizon Mine environmental obligation expense that was recorded in 2022 and reversed as a regulatory item in 2023 as part of our June 2023 Class A rate schedule (A-41) filing with FERC with a planned January 1, 2024 effective date.

Year ended December 31, 2022 compared to year ended December 31, 2021

For discussion of our results of operations comparing the year ended December 31, 2022 to the year ended December 31, 2021, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of our 2022 Annual Report on Form 10-K, filed with the SEC on March 10, 2023.

Financial Condition as of December 31, 2023 compared to December 31, 2022

Assets

Construction work in progress increased $82.4 million, or 101.0 percent, to $164.0 million as of December 31, 2023 compared to $81.6 million as of December 31, 2022. The increase was due to capital expenditures of $161.1 million, primarily for 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 $78.7 million.

Allowances for depreciation and amortization increased $347.6 million, or 14.5 percent, to $2.740 billion as of December 31, 2023 compared to $2.392 billion as of December 31, 2022. Because of our June 2023 Class A rate schedule (A-41) filing that uses a formula rate and the during evaluation of the probability of such filing as part of preparing these financial statements, we recognized the early retirement of Craig Station Units 2 and 3 that is part of our rate filing with FERC and thus we 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 December 2039 for Craig Station Unit 2 and January 2030 through December 2043 for Craig Station Unit 3. Additionally, $113.4 million was recorded to depreciation, amortization and depletion expense during 2023.

Investments in other associations increased $10.2 million, or 5.8 percent, to $187.7 million as of December 31, 2023 compared to $177.5 million as of December 31, 2022. The increase was primarily due to a Basin patronage capital allocation of $13.0 million and a CoBank patronage capital allocation of $2.7 million partially offset by patronage capital retirements of $9.1 million (primarily due to a Basin patronage capital retirement of $5.0 million and a CoBank patronage capital retirement of $3.1 million).

Coal inventory increased $20.3 million, or 58.3 percent, to $55.0 million as of December 31, 2023 compared to $34.7 million as of December 31, 2022. The increase was primarily due to receiving more coal than was consumed as a result of lower generation and maintenance outages at Craig Station. Additionally, coal inventory increased at Springerville Unit 3 as delivery issues were resolved and inventory was returned to normal levels.

Materials and supplies inventory increased $13.4 million, or 14.3 percent, to $106.9 million as of December 31, 2023 compared to $93.5 million as of December 31, 2022. The increase was primarily due to the disruption in the global supply chain for the procurement and delivery of inventory-related items and generally higher prices to purchase these items.

Regulatory assets increased $269.1 million, or 41.4 percent, to $919.5 million as of December 31, 2023 compared to $650.4 million as of December 31, 2022. The increase was primarily due to $261.6 million of expense related to the Craig Station Units 2 and 3 impairment loss that was recognized and deferred as a regulatory asset in December 2023 and the reversal of $44.9 million of environmental obligation expense that was recorded in 2022 and recognized as a regulatory asset in 2023. These regulatory assets were included in our June 2023 Class A rate schedule (A-41) filing with FERC with a planned January 1, 2024 effective date. These increases in regulatory assets were partially offset by amortization of $32.3 million to depreciation, amortization and depletion expense and recovered from our Utility Members through rates.

Equity and Liabilities

Long-term debt increased $27.0 million to $2.897 billion as of December 31, 2023 compared to $2.870 billion as of December 31, 2022 and current maturities of long-term debt increased $130.6 million, or 140.6 percent, to $223.5 million as of December 31, 2023 compared to $92.9 million as of December 31, 2022. The total increase of $157.6 million was primarily due to $300 million of Term SOFR rate loans under the 2022 Revolving Credit Agreement, a $150 million draw on the syndicated variable rate term loan and a $100 million fixed rate loan with CFC which were used partially as a committed take out of long-term debt and to support liquidity and capital projects. These increases in long-term debt were partially offset by the pay down of $300 million of Term SOFR rate loans under the 2022 Revolving Credit Agreement and $94.4 million in scheduled debt payments.

Short-term borrowings decreased $89.8 million to $184.3 million as of December 31, 2023 compared to $274.1 million as of December 31, 2022. The decrease was due to the pay down of all commercial paper in June 2023, which was funded by $300 million of Term SOFR rate loans under the 2022 Revolving Credit Agreement. In December 2023, we paid off $300 million loans under the 2022 Revolving Credit Agreement with an issuance of $185 million of commercial paper, $100 million from proceeds of long-term debt and the remaining in operating cash. Additionally, in June 2023, we acquired land in the amount of $600,000. Of the total purchase, $100,000 is due within 12 months and is included in short-term borrowings and the remaining balance is payable in equal amounts to 2029 and is included in long-term debt.

Regulatory liabilities decreased $47.6 million, or 95.4 percent, to $2.3 million as of December 31, 2023 compared to $49.9 million as of December 31, 2022. The decrease was primarily due to the recognition of $47.1 million of previously deferred membership withdrawal income.

Asset retirement obligations increased $14.0 million, or 7.7 percent, to $195.6 million as of December 31, 2023 compared to $181.6 million as of December 31, 2022. The increase was primarily due to an asset retirement obligation adjustment at Colowyo Mine's South Taylor pit of $31.2 million (related to the timing of a revised closure estimate) and an asset retirement obligation adjustment at Craig Station of $3.2 million (related to a change in timing of settlement from 2044 to

2030 as part of our June 2023 Class A rate schedule (A-41) filing with FERC with a planned January 1, 2024 effective date). These increases were partially offset by asset retirement obligation settlements of $5.5 million.

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 December 31, 2023, we had $106.0 million in cash and cash equivalents. Our committed credit arrangement as of December 31, 2023 is as follows (dollars in thousands):

	Authorized Amount	Available December 31, 2023
2022 Revolving Credit Agreement	$ 520,000 (1)	$ 335,795 (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 at December 31, 2023 was $185 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 $315 million of the commercial paper back-up sublimit remained available as of December 31, 2023. As of December 31, 2023, we had $336 million of availability under the 2022 Revolving Credit Agreement.

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 (1.125 percent as of December 31, 2022) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (0.125 percent as of December 31, 2022) 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 and plus a margin (1.125 percent as of December 31, 2022) based on our credit ratings. We had no outstanding borrowings as of December 31, 2023.

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 at December 31, 2023, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of December 31, 2023, we had $185 million of commercial paper outstanding (prior to netting discounts) and $315 million available on the commercial paper back-up sublimit.

On March 24, 2023, we entered into a two-year, $150 million variable rate syndicated multiple advance term loan agreement with CoBank, as the administrative agent. On the date of closing, we drew $100 million from the loan. On June 13, 2023, we drew the remaining $50 million from the loan.

On December 19, 2023, we entered into a 27 year, $100 million fixed rate term loan with CFC.

The First Mortgage Bonds, Series 2014 E-1, of $128 million, are maturing in November 2024. We will refinance or repay this debt depending upon market conditions, liquidity, and Utility Member withdrawals and the amount of contract termination payments received. See "—Results of Operations - Member Withdrawals."

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 or otherwise and may continue to seek to retire or purchase our outstanding debt. 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 are aligned with our business and the long-term health of our cooperative.

Our material cash requirements include the following contractual and other obligations.

Debt. As of December 31, 2023, we had $3.1 billion in outstanding obligations, including approximately $2.9 billion of debt outstanding under our Master Indenture, with $223.5 million payable in 2024. We have total future interest payments of $1.98 billion, with $159.5 million payable in 2024.

Construction Obligations. As of December 31, 2023, we had $38.8 million in contractual obligations to complete certain construction projects associated with our generating facilities and transmission system, with $19.5 million payable in 2024.

Coal Purchase Obligations. As of December 31, 2023, we had $240.9 million in contractual obligations to purchase coal for our generating facilities under long-term contracts that expire between 2024 and 2041, including $99.2 million payable in 2024. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions. This does not include any coal purchase obligations with our subsidiaries.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, the 2022 Revolving Credit Agreement, and expected contract termination payments from withdrawing Utility Members. See "—Results of Operations - Member Withdrawals."

Cash Flow

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

Year ended December 31, 2023 compared to year ended December 31, 2022

Operating activities. Net cash provided by operating activities was $124.4 million in 2023 compared to $152.6 million in 2022, a decrease of $28.2 million. The decrease in net cash provided by operating activities was impacted by the timing of payment of trade payables, an increase in coal inventory and higher cash deposits related to interconnection customers.

Investing activities. Net cash used in investing activities was $175.1 million in 2023 compared to $126.1 million in 2022, an increase in net cash used in investing activities of $49.0 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.

Financing activities. Net cash provided by financing activities was $50.0 million in 2023 compared to net cash used in financing activities of $21.0 million in 2022, an increase in net cash provided by financing activities of $71.0 million. The increase in net cash provided by financing activities was primarily due to the issuance of $550 million of long-term debt to support liquidity and capital expenditures. The increase was partially offset by higher payments of long-term debt, higher patronage capital retirements and a decrease in short-term borrowings in 2023 compared to 2022.

Year ended December 31, 2022 compared to year ended December 31, 2021

For discussion of our cash flow comparing 2022 to 2021, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow" in Item 7 of our 2022 Annual Report on Form 10-K, filed with the SEC on March 10, 2023.

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 preferred IRA scenario as part of our Phase I 2023 ERP, in the years 2024 through 2028, we forecast that we may invest approximately $2.59 billion in new facilities and upgrades to our existing facilities. Our investment forecast for new facilities and upgrades to existing facilities by capital expenditure category is as follows (dollars in thousands):

	2024	2025	2026	2027	2028	Total
Generation	$ 207,167	$ 604,395	$ 227,450	$ 257,847	$ 356,066	$ 1,652,925
Transmission	144,837	197,608	133,438	158,825	147,384	782,092
General Plant	39,210	27,708	31,654	28,211	28,046	154,829
Total Capital Expenditures	$ 391,214	$ 829,711	$ 392,542	$ 444,883	$ 531,496	$ 2,589,846

Our actual capital expenditures depend on a variety of factors, including assumptions related to our Responsible Energy Plan and our Phase I 2023 ERP, Utility Member load growth or Utility Member withdrawals, partial requirements options, availability of necessary permits, regulatory changes, environmental requirements, inflation, construction delays and costs, receipt of New ERA Program funding, 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 Utility Members' service territories.

Rating Triggers

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

Our 2022 Revolving Credit Agreement includes a pricing grid related to the Term SOFR spread, commitment fee and letter of credit fees due under the facility. 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 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Fair Value of Debt

The fair values of 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 carrying amounts and fair values of our debt as of December 31, 2023 and 2022 are as follows:

	December 31, 2023		December 31, 2022	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,137,534	$ 2,909,301	$ 2,981,481	$ 2,725,606

Commodity Price Risk

As a wholesale provider of energy to our Utility Members, we could have exposure to the market price of energy to meet our obligations. We engage in various hedging activities for both natural gas and electricity to mitigate our exposure to market price volatility.

We have an established energy risk management program to manage the commodity price risks associated with natural gas, coal, and electric purchases and electric sales and their potential impact on our Utility Member rates. As a result, our primary risk with respect to energy market price fluctuations in the near-term results from any prolonged and unanticipated outages from our various generating facilities.

As of December 31, 2023, we have available for our use approximately 440 MWs of simple-cycle turbine capacity that is capable of operating on either natural gas or distillate fuel oil. As of December 31, 2023, we also have available for our use approximately 110 MWs of distillate fuel oil-only simple-cycle turbine capacity, and 272 MWs of our natural gas-only combined-cycle capacity, which affords substantial flexibility in meeting our obligations to serve our Utility Members. In 2023, these resources provided approximately 9.0 percent of our energy available for sale. We expect the use of our natural gas-fired generating facilities to increase with the addition of new renewable resources and the closure of our coal-fired generating facilities.

Risk Management

We have an established risk management programs which address both enterprise and energy commodity risks. These programs oversee all the risk functions and address commodity price volatility, counterparty exposure, credit risk, trading controls and hedging strategies. A corporate committee, consisting of senior executives and support staff, meets regularly to assess market behavior, hedging activities and other corporate risks. Our Board is given briefings on risk management activities. Additionally, pursuant to Board policy, the Finance and Audit Committee and the Chief Executive Officer annually determine whether an external independent assessment of our risk management programs shall be performed. We had this independent assessment performed in 2023 and are reviewing the recommendations.

Interest Rate Risk

We have an established risk management program to address interest rate risk. This program is designed to balance achieving the lowest costs associated with current and future debt issuances while also mitigating the impact of floating interest rates.

As of December 31, 2023, we were exposed to the risk of changes in interest rates related to our $761.1 million of variable rate debt, comprised of $152.2 million of variable rate CFC notes, $273.9 million of variable rate CoBank notes, $150 million of a syndicated variable rate term loan, and $184.2 million of variable rate commercial paper notes. As of December 31, 2023, the weighted average interest rate on this variable rate debt was 6.55 percent.

In 2023, we amended our variable rate loan documents with CFC and CoBank and replaced the LIBOR based rate with Term SOFR.

Our objective in managing interest rate risk is to maintain a balance of fixed and variable rate debt that will lower our overall borrowing costs within reasonable risk parameters. As of December 31, 2023, we had 22.91 percent of our total debt in variable rate loans. An increase in interest rates of 100 basis points would increase our annual debt service by approximately $7.6 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

To the Members and the Board of Directors of Tri-State Generation and Transmission Association, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of Tri-State Generation and Transmission Association, Inc. (the "Association") as of December 31, 2023 and 2022, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Association at December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Association's management. Our responsibility is to express an opinion on the Association's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Association in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Association is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Association's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Asset Retirement Obligations – Colowyo Coal Mines

Description of the matter	As discussed in Note 2 and Note 4 to the consolidated financial statements, the Association's obligations for the final reclamation costs and post-reclamation monitoring of the Association's coal mines are recognized at management's estimated fair value at the time the obligations are incurred and capitalized as part of the related long-lived asset or reflected in earnings in the period an estimate is revised, as applicable. As changes in estimates occur, such as mine plans, estimated costs and timing of reclamation activities, the Association makes revisions to the asset retirement obligation at the appropriate discount rate. Auditing the Association's asset retirement obligations for coal mines required us to make subjective auditor judgements because the estimates underlying the determination of the obligations were based on significant assumptions utilized by management and their engineering staff. In particular, the fair value calculations of the asset retirement obligations are based on, among other things, estimates of disturbed areas, reclamation costs, timing of reclamation activities, and probability of outcomes.
How we addressed the matter in our audit	To audit the asset retirement obligations for coal mines, our procedures included evaluating the appropriateness of the Association's methodology and testing significant assumptions, as discussed above, and the underlying data used by the Association in its estimate. To assess the estimates of disturbed areas, reclamation costs, timing of reclamation activities, and probability of outcomes, we evaluated significant changes from the prior year estimate and verified consistency between the timing of activities to the projected mine life or reclamation plan. We also considered the appropriateness of the estimated reclamation costs for coal mines, compared anticipated labor and equipment costs to recent operating data and third-party evidence including common industry references, and recalculated management's estimate. We involved our specialists in our assessment of the Association's asset retirement obligations including reviewing the Association's methodology, interviewing members of the Association's engineering staff, evaluating the reasonableness of the cost estimates and assumptions, and assessing completeness of the estimate with respect to regulatory requirements.

/s/ Ernst & Young LLP

We have served as the Association's auditor since 1977.

Denver, Colorado
March 15, 2024

Tri-State Generation and Transmission Association, Inc.
Consolidated Statements of Financial Position
(dollars in thousands)

	December 31, 2023	December 31, 2022
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,722,679	$ 5,659,423
Construction work in progress	163,954	81,555
Total electric plant	**5,886,633**	**5,740,978**
Less allowances for depreciation and amortization	(2,739,924)	(2,392,363)
Net electric plant	**3,146,709**	**3,348,615**
Other plant	952,318	954,144
Less allowances for depreciation, amortization and depletion	(711,896)	(694,774)
Net other plant	**240,422**	**259,370**
Total property, plant and equipment	**3,387,131**	**3,607,985**
Other assets and investments		
Investments in other associations	187,684	177,477
Investments in and advances to coal mines	1,619	1,914
Restricted cash and investments	3,408	4,257
Other noncurrent assets	15,264	15,828
Total other assets and investments	**207,975**	**199,476**
Current assets		
Cash and cash equivalents	106,005	105,852
Restricted cash and investments	605	573
Deposits and advances	37,455	34,233
Accounts receivable—Utility Members	101,394	103,246
Other accounts receivable	23,123	32,436
Coal inventory	54,979	34,723
Materials and supplies	106,893	93,514
Total current assets	**430,454**	**404,577**
Deferred charges		
Regulatory assets	919,483	650,421
Prepayment—NRECA Retirement Security Plan	5,372	10,745
Other	36,121	40,445
Total deferred charges	**960,976**	**701,611**
Total assets	**$ 4,986,536**	**$ 4,913,649**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 984,581	$ 984,865
Accumulated other comprehensive loss	(839)	(468)
Noncontrolling interest	134,269	126,180
Total equity	**1,118,011**	**1,110,577**
Long-term debt	2,896,506	2,869,963
Total capitalization	**4,014,517**	**3,980,540**
Current liabilities		
Utility Member advances	14,333	17,070
Accounts payable	123,674	109,109
Short-term borrowings	184,305	274,102
Accrued expenses	39,268	42,506
Current asset retirement obligations	21,635	5,419
Accrued interest	24,549	25,431
Accrued property taxes	31,986	36,477
Current maturities of long-term debt	223,523	92,920
Total current liabilities	**663,273**	**603,034**
Deferred credits and other liabilities		
Regulatory liabilities	2,317	49,931
Deferred income tax liability	15,223	19,275
Asset retirement and environmental reclamation obligations	195,566	181,588
Other	84,125	68,374
Total deferred credits and other liabilities	**297,231**	**319,168**
Accumulated postretirement benefit and postemployment obligations	11,515	10,907
Total equity and liabilities	**$ 4,986,536**	**$ 4,913,649**

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

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

	For the years ended December 31, 2023	2022	2021
Operating revenues			
Member electric sales	$ 1,208,352	$ 1,213,234	$ 1,161,291
Non-member electric sales	145,228	163,355	114,908
Rate stabilization	47,127	95,613	78,457
Provision for rate refunds	94	(51)	(10,196)
Other	66,615	61,420	56,341
	1,467,416	**1,533,571**	**1,400,801**
Operating expenses			
Purchased power	404,876	409,513	381,477
Fuel	258,894	329,046	236,089
Production	191,095	177,413	185,016
Transmission	187,874	175,889	182,327
General and administrative	88,621	79,640	57,243
Depreciation, amortization and depletion	171,460	184,047	190,237
Coal mining	44,548	9,899	5,323
Other	(31,341)	53,509	7,191
	1,316,027	**1,418,956**	**1,244,903**
Operating margins	**151,389**	**114,615**	**155,898**
Other income			
Interest	8,614	4,447	3,609
Capital credits from cooperatives	19,369	26,185	9,466
Other	11,447	10,027	4,152
	39,430	**40,659**	**17,227**
Interest expense			
Interest	175,557	148,609	143,328
Interest charged during construction	(4,800)	(1,486)	(3,786)
	170,757	**147,123**	**139,542**
Income tax expense (benefit)	4	(249)	295
Net margins including noncontrolling interest	**20,058**	**8,400**	**33,288**
Net margin attributable to noncontrolling interest	(9,971)	(8,400)	(6,942)
Net margins attributable to the Association	**$ 10,087**	**$ —**	**$ 26,346**

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

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

	For the years ended December 31,		
	2023	2022	2021
Net margins including noncontrolling interest	$ 20,058	$ 8,400	$ 33,288
Other comprehensive income (loss):			
Unrealized loss on securities available for sale	127	(333)	(108)
Unrecognized prior service credit on postretirement benefit obligation	—	—	5,698
Unrecognized actuarial gain on postretirement benefit obligation	757	32	784
Amortization of actuarial loss on postretirement benefit obligation included in net margin	(84)	102	78
Amortization of prior service credit on postretirement benefit obligation included in net margin	(1,637)	(1,636)	(2,139)
Unrecognized actuarial gain (loss) on executive benefit restoration obligation	(909)	1,740	(778)
Unrecognized prior service cost on executive benefit restoration obligation	—	(308)	(1,050)
Amortization of actuarial loss on executive benefit restoration obligation included in net margin	219	426	515
Curtailment and settlement	—	(187)	141
Amortization of prior service cost on executive benefit restoration obligation included in net margin	1,156	1,156	1,113
Other comprehensive income (loss)	**(371)**	**992**	**4,254**
Comprehensive income including noncontrolling interest	**19,687**	**9,392**	**37,542**
Net comprehensive income attributable to noncontrolling interest	(9,971)	(8,400)	(6,942)
Comprehensive income attributable to the Association	**$ 9,716**	**$ 992**	**$ 30,600**

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

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

	For the years ended December 31,		
	2023	2022	2021
Patronage capital equity at beginning of period	$ 984,865	$ 994,865	$ 978,519
Net margins attributable to the Association	10,087	—	26,346
Retirement of patronage capital	(10,371)	(10,000)	(10,000)
Patronage capital equity at end of period	**984,581**	**984,865**	**994,865**
Accumulated other comprehensive loss at beginning of period	(468)	(1,460)	(5,714)
Unrealized gain (loss) on securities available for sale	127	(333)	(108)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net margin	(84)	102	78
Reclassification adjustment for prior service credit on postretirement benefit obligation included in net margin	(1,637)	(1,636)	(2,139)
Reclassification adjustment for actuarial loss on executive benefit restoration obligation included in net margin	219	426	515
Curtailment and settlement	—	(187)	141
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	1,156	1,156	1,113
Unrecognized prior service credit on postretirement benefit obligation	—	—	5,698
Unrecognized actuarial gain on postretirement benefit obligation	757	32	784
Unrecognized actuarial gain (loss) on executive benefit restoration obligation	—	1,740	(778)
Unrecognized prior service cost on executive benefit restoration obligation	(909)	(308)	(1,050)
Accumulated other comprehensive loss at end of period	**(839)**	**(468)**	**(1,460)**
Noncontrolling interest at beginning of period	126,180	119,100	114,851
Net comprehensive income attributable to noncontrolling interest	9,971	8,400	6,942
Equity distribution to noncontrolling interest	(1,882)	(1,320)	(2,693)
Noncontrolling interest at end of period	**134,269**	**126,180**	**119,100**
Total equity at end of period	**$ 1,118,011**	**$ 1,110,577**	**$ 1,112,505**

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

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

	For the years ended December 31, 2023	2022	2021
Operating activities			
Net margins including noncontrolling interest	$ 20,058	$ 8,400	$ 33,288
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	171,460	184,047	190,237
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,372
Amortization of debt issuance costs	2,423	3,105	2,479
Impairment loss and other closure costs	261,600	29,098	—
Deferred impairment loss and other closure costs	(261,600)	(29,098)	—
Deposits associated with generator interconnection requests	9,880	6,716	17,130
Rate stabilization	(47,127)	(95,613)	(78,457)
Capital credit allocations from cooperatives and income from coal mines under (over) refund distributions	(9,911)	(14,115)	512
Changes in operating assets and liabilities:			
Accounts receivable	18,019	(30,135)	(3,618)
Coal inventory	(20,256)	24,978	(3,453)
Materials and supplies	(13,380)	(6,281)	(4,714)
Accounts payable and accrued expenses	2,333	19,102	13,114
Accrued interest	(1,882)	(285)	(1,804)
Accrued property taxes	(4,492)	2,600	1,082
New Horizon Mine environmental obligation	(44,869)	44,869	—
Other	36,773	(164)	(1,261)
Net cash provided by operating activities	**124,401**	**152,596**	**169,907**
Investing activities			
Purchases of plant	(179,398)	(121,527)	(118,422)
Changes in deferred charges	4,339	(4,617)	(13,054)
Proceeds from other investments	—	94	72
Net cash used in investing activities	**(175,059)**	**(126,050)**	**(131,404)**
Financing activities			
Changes in Member advances	(2,969)	(282)	183
Payments of long-term debt	(394,447)	(232,946)	(94,288)
Proceeds from issuance of long-term debt	550,000	—	—
Debt issuance costs	(664)	(1,475)	—
Change in short-term borrowings, net	(89,297)	224,105	49,997
Retirement of patronage capital	(10,044)	(8,445)	(18,067)
Equity distribution to noncontrolling interest	(1,882)	(1,320)	(2,693)
Other	(703)	(637)	(573)
Net cash provided by (used in) financing activities	**49,994**	**(21,000)**	**(65,441)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**(664)**	**5,546**	**(26,938)**
Cash, cash equivalents and restricted cash and investments – beginning	**110,682**	**105,136**	**132,074**
Cash, cash equivalents and restricted cash and investments – ending	**$ 110,018**	**$ 110,682**	**$ 105,136**
Supplemental cash flow information:			
Cash paid for interest	$ 173,147	$ 145,350	$ 143,394
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 1,005	$ (1,076)	$ 1,383

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

Tri-State Generation and Transmission Association, Inc.

Notes to Consolidated Financial Statements

NOTE 1 – ORGANIZATION

Tri-State Generation and Transmission Association, Inc. ("Tri-State," "we," "our," "us," or "the Association") is 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-two electric distribution member systems who are Class A members, to which we provide electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members. We have three 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 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 June 16, 2023, we filed with FERC a new Class A rate that uses a formula rate and requested for the new rate to take effect on January 1, 2024. See Note 14—Commitments and Contingencies—Legal.

We also sell a portion of our electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. In 2023, 2022 and 2021, total megawatt-hours sold were 18.2, 18.6 and 17.6 million, respectively, of which 90.7, 88.8 and 89.1 percent, respectively, were sold to Utility Members. Total revenue from electric sales was $1.4 billion for 2023 and 2022 and $1.3 billion for 2021 of which 86.2, 82.4, and 86.4 percent in 2023, 2022 and 2021, respectively, was from Utility Member sales. Energy resources were provided by our generation and purchased power, of which 48.2, 54.3 and 52.1 percent in 2023, 2022 and 2021, respectively, were from our generation.

Power is provided to Utility Members at rates determined by our Board of Directors ("Board"), subject to FERC approval. Rates are designed to recover all costs and provide margins to increase Utility Members' equity and to meet certain financial covenants, including a debt service ratio ("DSR") requirement and equity to capitalization ratio ("ECR") requirement.

We supply wholesale power to our Utility Members through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. Our generating facilities also include undivided ownership interests in jointly owned generating facilities. See Note 3—Property, Plant and Equipment. In support of our coal-fired generating facilities, we have direct ownership in coal mines.

We, including our subsidiaries, employ 1,120 people, of which 215 are subject to collective bargaining agreements. None of these agreements expire within one year.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF CONSOLIDATION: Our consolidated financial statements include the accounts of 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 13—Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities.

All significant intercompany balances and transactions have been eliminated in consolidation. The accompanying consolidated statements have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") as applied to regulated enterprises.

JOINTLY OWNED FACILITIES: We own undivided interests in two jointly owned generating facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Yampa Project (operated by us) and the Missouri Basin Power Project ("MBPP") (operated by Basin Electric Power Cooperative ("Basin")). Each participant in these agreements receives a portion of the total output of the generation facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and operating expenses is included in our consolidated financial statements. See Note 3—Property, Plant and Equipment.

SEGMENT REPORTING: We were organized for the purpose of supplying wholesale power to our Utility Members and do so through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. In support of our coal-fired generating resources, we have direct ownership in coal mines. Our Board serves as our chief operating decision maker who manages and reviews our operating results and allocates resources as one operating segment. Therefore, we have one reportable segment for financial reporting purposes. Our significant segment expenses include purchased power expense and fuel expense, which are regularly provided to our chief operating decision maker. As we have only one operating segment, these values agree to those disclosed in our Consolidated Statement of Operations.

USE OF ESTIMATES: The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

IMPAIRMENT EVALUATION: Long-lived assets (property, plant and equipment, intangible assets, investments and preliminary surveys and investigation costs) that are held and used are evaluated for impairment whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. An impairment loss is recognized when estimated undiscounted cash flows expected to result from the use of the asset plus net proceeds expected from disposition of the asset (if any) are less than the carrying value of the asset. When an impairment loss is recognized, the carrying amount of the asset is reduced to its estimated fair value based on quoted market prices or other valuation techniques. In 2023 as part of preparing our financial statements, we recognized an impairment loss of $261.6 million associated with the planned early retirement of Craig Generating Station Units 2 and 3. In 2022, we recognized an impairment loss of $3.7 million associated with the early retirement of the Rifle Generating Station. We also recognized an impairment loss of $25.4 million associated with additional asset retirement obligations at the Nucla and Escalante Generating Stations related to a change in cost estimates. There were no impairments of long-lived assets recognized in 2021. These impairment losses were deferred in accordance with the accounting requirements related to regulated operations at the discretion of our Board and subject to FERC approval, if applicable. See Note 2—Accounting for Rate Regulation.

VARIABLE INTEREST ENTITIES: We evaluate our arrangements and relationships with other entities, including our investments in other associations in accordance with the accounting standard related to consolidation of variable interest entities. This guidance requires us to identify variable interests (contractual, ownership or other financial interests) in other entities and whether any of those entities in which we have a variable interest meet the criteria of a variable interest entity. An entity is considered to be a variable interest entity when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. In making this assessment, we consider the potential that our arrangements and relationships with other entities provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of an entity, the ability to directly or indirectly make decisions about the entity's activities and other factors. If an entity that we have a variable interest in meets the criteria of a variable interest entity, we must determine whether we are the primary beneficiary of that entity. The primary beneficiary is the entity that has the power to direct the activities of the variable interest entity that most significantly impact the variable interest entity's economic performance, and the obligation to absorb losses or the right to receive benefits from the variable interest entity that could be potentially significant to the variable interest entity. If we are determined to be the primary beneficiary of (has controlling financial interest in) a variable interest entity, then we would be required to consolidate that entity. In certain situations, it may be determined that power is shared among multiple unrelated parties such that no one party has the power to direct the activities of a variable interest entity that most significantly impact the variable interest entity's economic performance (decisions about those activities require the consent of each of the parties sharing power). In accordance with the accounting guidance prescribed by consolidation of variable interest entities, if the determination is made that power is shared among multiple unrelated parties, then no party is the primary beneficiary. See Note 13—Variable Interest Entities.

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 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):

	December 31, 2023	December 31, 2022
Regulatory assets		
Deferred income tax expense (1)	$ 15,223	$ 19,279
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	74,551	76,842
Goodwill – J.M. Shafer (3)	37,749	40,598
Goodwill – Colowyo Coal (4)	33,062	34,095
Deferred debt prepayment transaction costs (5)	106,417	115,045
Deferred Holcomb expansion impairment loss (6)	74,795	79,470
New Horizon Mine environmental obligation (7)	44,869	—
Unrecovered plant (8)	532,817	285,092
Total regulatory assets	**919,483**	**650,421**
Regulatory liabilities		
Interest rate swap - realized gain (9) and other	1,854	2,341
Membership withdrawal (10)	463	47,590
Total regulatory liabilities	**2,317**	**49,931**
Net regulatory asset	**$ 917,166**	**$ 600,490**

(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 in rates.

(3) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP ("TCP") in December 2011. Goodwill is 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 in rates.

(4) Represents goodwill related to our acquisition of Colowyo Coal Company LP ("Colowyo Coal") in December 2011. Goodwill is 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 in 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 in 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 other operating expenses in the amount of $4.7 million annually over the 20-year period ending in 2039 and recovered from our Utility Members in rates.

(7) Represents $44.9 million of New Horizon Mine environmental obligation expense that was recorded in 2022 and reversed as a regulatory item in 2023 as part of our June 2023 Class A rate schedule (A-41) filing with FERC with a planned January 1, 2024 effective date. 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 beginning in 2024 through 2048 and recovered from our Utility Members in rates.

(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 2045, which was the depreciable life of Escalante Generating Station, and recovered from our Utility Members through rates. The annual amortization approximates the former annual Escalante Generating Station depreciation for the remaining life of the asset. 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 2028, which was the depreciable life of the Rifle Generating Station, and recovered from our Utility Members in rates. Because of our June 2023 Class A rate schedule (A-41) filing that uses a formula rate and the during evaluation of the probability of such

filing as part of preparing these financial statements, we recognized the early retirement of Craig Station Units 2 and 3 that is part of our rate filing with FERC and thus we 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 deferral of the recognition of other operating revenues related to the withdrawal of former Utility Members from membership in us. The deferred membership withdrawal income will be refunded to Utility Members through reduced rates when recognized in operating revenues. During 2023, $47.1 million was recognized in operating revenues as part of our rate stabilization measures.

ELECTRIC PLANT AND DEPRECIATION: Electric plant is stated at cost. The cost of internally constructed assets includes payroll, overhead costs and interest charged during construction. Interest rates charged during construction were 5.2 percent for 2023, 2.3 percent for 2022 and 4.4 percent for 2021. During 2022, Tri-State transitioned from using the "Indirect Costs" ("IDC") rate to the FERC prescribed "Allowance For Funds Used During Construction" ("AFUDC") rate. AFUDC is defined as the gross allowance for borrowed funds used during construction. The AFUDC rate is calculated with the assumption that short-term debt is the first source of funds used for construction. Any construction not covered by the short-term debt is then assumed to be covered by long-term debt. The AFUDC rate varies from the IDC rate, which assumes that total debt was used to cover construction costs. The amount of interest capitalized during construction was $4.8, $1.5 and $3.8 million during 2023, 2022 and 2021, respectively. At the time that units of electric plant are retired, original cost and cost of removal, net of the salvage value, are charged to the allowance for depreciation. Replacements of electric plant that involve less than a designated unit value are charged to maintenance expense when incurred. Electric plant is depreciated based upon estimated depreciation rates and useful lives that are periodically re-evaluated. See Note 3—Property, Plant and Equipment.

COAL RESERVES AND DEPLETION: Coal reserves are recorded at cost. Depletion of coal reserves is computed using the units-of-production method utilizing only proven and probable reserves.

LEASES: 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. See Note 11—Leases.

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 incurred.

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):

	December 31, 2023	December 31, 2022
Basin Electric Power Cooperative	$ 135,652	$ 127,640
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,451	12,172
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,054	15,054
CoBank, ACB	18,809	16,727
Other	5,718	5,884
Investments in other associations	**$ 187,684**	**$ 177,477**

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 2023, 2022 or 2021.

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 have been restricted by contract and 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 restricted by contract or other legal reasons and 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.

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 estimated fair value of the investments at December 31, 2023 were $0.6 million and $0.5 million, respectively. The cost and estimated fair value of the investments at December 31, 2022 were $0.6 million and $0.5 million, respectively.

INVENTORIES: Coal inventories at our owned generating facilities are stated at LIFO (last-in, first-out) cost and were $29.0 million and $3.7 million as of December 31, 2023 and 2022, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2023, there was no lower coal fuel expense as a result of a LIFO inventory liquidation at our generating facilities.

OTHER DEFERRED CHARGES: 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 11—Leases.

Other deferred charges are as follows (dollars in thousands):

	December 31, 2023	December 31, 2022
Preliminary surveys and investigations	$ 12,845	$ 13,048
Advances to operating agents of jointly owned facilities	2,750	7,324
Operating lease right-of-use assets	6,477	6,771
Other	14,049	13,302
Total other deferred charges	**$ 36,121**	**$ 40,445**

DEBT ISSUANCE COSTS: We account for debt issuance costs as a direct deduction of the associated long-term debt carrying amount consistent with the accounting for debt discounts and premiums. Deferred debt issuance costs are amortized to interest expense using an effective interest method over the life of the respective debt.

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 a market risk premium. As changes in estimates occur, such as mine plans, estimated costs, and timing of the performance of reclamation activities, we make revisions to the asset and obligation at the appropriate discount rate. Upon settlement of an asset retirement obligation, we 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. Estimates of future expenditures for environmental reclamation obligations are not discounted. See Note 4—Asset Retirement and Environmental Reclamation Obligations.

OTHER DEFERRED CREDITS AND OTHER LIABILITIES: In 2015, we renewed transmission right-of-way easements on tribal nation lands where certain of our electric transmission lines are located. We will pay $25.7 million for these easements from 2023 through the individual easement terms ending between 2036 and 2040. The present value of the remaining easement payments was $17.9 million and $18.6 million as of December 31, 2023 and December 31, 2022, respectively, which is 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 the reclamation costs at jointly owned facilities in which we have undivided interests in.

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.

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

	December 31, 2023	December 31, 2022
Transmission easements	$ 17,862	$ 18,636
OATT deposits	27,872	17,476
Financial liabilities - reclamation	16,895	12,429
Customer deposits	12,091	8,616
Contract liabilities (unearned revenue) - noncurrent	3,125	3,765
Operating lease liabilities - noncurrent	1,396	1,251
Other	4,884	6,201
Total other deferred credits and other liabilities	**$ 84,125**	**$ 68,374**

PATRONAGE CAPITAL: Our net margins are treated as advances of capital from our Members and are allocated to our Utility Members on the basis of their electricity purchases from us and to our Non-Utility Members as provided in their respective membership agreements. Margins not yet distributed to Members constitute patronage capital. Patronage capital is held for the account of our Members and is distributed through patronage capital retirements when our Board deems it appropriate to do so, subject to debt instrument restrictions.

ELECTRIC SALES REVENUE: Revenue from electric energy deliveries is recognized when delivered. See Note 10—Revenue.

OTHER OPERATING REVENUE: Other operating revenue consists primarily of wheeling, transmission, and coal sales revenue. See Note 10—Revenue.

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 effective 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 payable that will be settled or received through future rate revenues. Under this regulatory accounting approach, any income tax expense or benefit on our consolidated statements of operation includes only the current portion. Pursuant to our new Class A rate that uses a formula rate filed with FERC, we will follow the flow-through method which will not have a material impact on our financial statements. See Note 9—Income Taxes.

INTERCHANGE POWER: We occasionally engage in interchanges, or non-cash swapping, of energy. Based on the assumption that all energy interchanged will eventually be received or delivered in-kind, interchanged energy is generally valued at the average cost of fuel to generate power. Additionally, portions of the energy interchanged are valued per contract with the utility involved in the interchange. When we are in a net energy advance position, the advanced energy balance is recorded as an asset. If we owe energy, the net energy balance owed to others is recorded as a liability. The net activity for the year is included in purchased power expense. The interchange liability balance of $4.1 million and $4.7 million at December 31, 2023 and 2022, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was a credit of $2.1 million in 2023, an expense of $1.5 million in 2022 and an expense of $0.6 million in 2021.

ACCOUNTING PRONOUNCEMENTS - 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 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: At 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**

At December 31, 2022, 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 %	$ 3,048,918	$ (1,353,042)	$ 1,695,876
Transmission plant	1.11 % to 2.09 %	1,956,378	(690,517)	1,265,861
General plant	1.46 % to 9.53 %	412,879	(257,761)	155,118
Other	2.75 % to 10.00 %	241,248	(91,043)	150,205
Electric plant in service (at cost)		**$ 5,659,423**	**$ (2,392,363)**	**3,267,060**
Construction work in progress				81,555
Electric plant				**$ 3,348,615**

At December 31, 2023, we had $38.9 million of commitments to complete construction projects, of which approximately $19.5, $15.3 and $4.1 million are expected to be incurred in 2024, 2025 and 2026, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2023 (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	$ 358,839	$ 23
MBPP - Laramie River Station	28.50 %	540,365	346,959	2,114
Total		**$ 932,875**	**$ 705,798**	**$ 2,137**

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):

	December 31, 2023	December 31, 2022
Colowyo Mine assets	$ 396,441	$ 386,898
New Horizon Mine assets	6,448	5,995
Accumulated depreciation and depletion	(184,239)	(155,653)
Net mine assets	**218,650**	**237,240**
Non-utility assets	549,430	561,251
Accumulated depreciation	(527,658)	(539,121)
Net non-utility assets	**21,772**	**22,130**
Net other plant	**$ 240,422**	**$ 259,370**

NOTE 4 – ASSET RETIREMENT AND ENVIRONMENTAL RECLAMATION OBLIGATIONS

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, ash landfill and underground storage tanks at the generating facilities.

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

	2023	2022
Obligations at beginning of period	$ 187,007	$ 90,281
Liabilities incurred	—	—
Liabilities settled	(5,711)	(3,184)
Accretion expense	5,298	6,163
Change in estimate	30,607	93,747
Total obligations at end of period	**$ 217,201**	**$ 187,007**
Less current obligations at end of period	(21,635)	(5,419)
Long-term obligations at end of period	**$ 195,566**	**$ 181,588**

During 2023, we increased the asset retirement obligations related to two pits at the Colowyo Mine by $25.5 million due to revised cost estimates and timing adjustments, with an offsetting decrease in the asset retirement obligation related to the third pit of $1.4 million due to reclamation costs paid and a gain on settlement. In the second quarter of 2022, we increased the environmental reclamation obligation at the New Horizon Mine by $44.9 million due to revised cost estimates. The New Horizon Mine environmental remediation liability is $67.3 million as of December 31, 2023. 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 statement of operations. In the fourth quarter of 2023, we reversed the $44.9 million of environmental obligation expense that was recorded in 2022 as a regulatory item to be amortized to expense over 25 years and recovered from our Utility Members through rates. During 2022, we recorded an additional asset retirement obligation of $36.8 million related to a change in cost estimates for our pond, ash landfill and post-closure reclamation obligations at various generating facilities.

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.

NOTE 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

Contract Assets

A contract asset represents an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer when that right is conditioned on something other than the passage of time (for example, the entity's future performance). We have no contract assets as of December 31, 2023 and December 31, 2022.

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 10—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. We recognized $1.0 million of this unearned revenue in 2023 in other operating revenues on our consolidated statements of operations.

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

	December 31, 2023	December 31, 2022
Accounts receivable - Members	**$ 101,394**	**$ 103,246**
Other accounts receivable - trade:		
Non-member electric sales	9,657	17,213
Other	11,077	9,141
Total other accounts receivable - trade	**20,734**	**26,354**
Other accounts receivable - nontrade	2,389	6,082
Total other accounts receivable	**$ 23,123**	**$ 32,436**
Contract liabilities (unearned revenue)	**$ 4,159**	**$ 5,123**

NOTE 6 – LONG-TERM DEBT

We have $2.9 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture"). Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a DSR requirement on an annual basis and an 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. We had no outstanding borrowings under the 2022 Revolving Credit Agreement as of December 31, 2023. As of December 31, 2023, we had $336 million in availability (including $315 million under the commercial paper back-up sublimit) under the 2022 Revolving Credit Agreement.

On March 24, 2023, we entered into a two-year, $150 million variable rate syndicated multiple advance term loan agreement with CoBank, ACB, as the administrative agent. On the date of closing, we drew $100 million from the loan. On June 13, 2023, we drew the remaining $50 million from the loan.

On December 19, 2023 we entered into a 27-year, $100 million fixed rate term loan with CFC.

The First Mortgage Bonds, Series 2014 E-1, of $128 million, are maturing in November 2024. We will refinance or repay this debt depending upon market conditions, liquidity, Utility Member withdrawals and the amount of contract termination payments received.

Long-term debt, including applicable terms and interest rates as of December 31, 2023, consists of the following (dollars in thousands):

	December 31, 2023	December 31, 2022
Mortgage notes payable		
2.32% to 6.44% CFC, due through 2050	$ 177,260	$ 85,855
2.63% to 4.43% CoBank, ACB, due through 2042	159,736	174,985
First Mortgage Obligations, Series 2017A, Tranche 1, 3.34%, due through 2029	60,000	60,000
First Mortgage Obligations, Series 2017A, Tranche 2, 3.39%, due through 2029	60,000	60,000
First Mortgage Bonds, Series 2016A, 4.25% due 2046	228,783	228,783
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	128,002	128,002
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	250,000	250,000
First Mortgage Bonds, Series 2010A, 6.00% due 2040	499,805	499,805
First Mortgage Obligations, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000	180,000
First Mortgage Obligations, Series 2014B, Tranche 2, 4.30%, due through 2039	20,000	20,000
First Mortgage Obligations, Series 2014B, Tranche 3, 4.45%, due through 2045	550,000	550,000
Variable rate CFC, SOFR-based term loans, due through 2049	152,220	152,220
Variable rate CoBank, ACB, SOFR-based term loans, due through 2044	273,925	296,430
Syndicated variable rate, SOFR-based term loan due 2025	150,000	—
Pollution control revenue bonds		
Moffat County, CO, 2.90% term rate through October 2027, Series 2009, due 2036	46,800	46,800
Springerville certificates and other debt		
Series B, 7.14%, due through 2033	200,503	248,601
New Horizon Mine remaining land installment payments	500	—
Total long-term debt	**3,137,534**	**2,981,481**
Less debt issuance costs	(19,723)	(21,481)
Less debt discounts	(8,678)	(8,960)
Plus debt premiums	10,896	11,843
Total debt adjusted for discounts, premiums and debt issuance costs	**3,120,029**	**2,962,883**
Less current maturities	(223,523)	(92,920)
Long-term debt	**$ 2,896,506**	**$ 2,869,963**

Annual maturities of total long-term debt adjusted for debt issuance costs, discounts and premiums at December 31, 2023 are as follows (dollars in thousands):

2024 (1)	$ 223,523
2025 (2)	238,845
2026	90,538
2027	92,421
2028	99,241
Thereafter	2,375,461
	$ 3,120,029

(1) Includes $128 million bullet maturity for the First Mortgage Bonds, Series 2014 E-1.

(2) Includes $150 million maturity for the syndicated variable rate SOFR-based term loan.

NOTE 7 – 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.

Commercial paper consisted of the following (dollars in thousands):

	2023	2022
Commercial paper outstanding, net of discounts	$ 184,205	$ 274,102
Short-term borrowings - other	$ 100	$ —
Weighted average interest rate	5.62 %	4.61 %

At December 31, 2023, $315 million of the commercial paper back-up sublimit remained available under the 2022 Revolving Credit Agreement. See Note 6—Long-Term Debt.

NOTE 8 – 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 market, or in the most advantageous market when no principal market exists. The fair value measurements 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 and 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.

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 investments in the Executive Benefit Restoration Plan trust are as follows (dollars in thousands):

	December 31, 2023		December 31, 2022	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 10,821	$ 10,298	$ 10,604	$ 9,808

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 amortized cost and fair values of our marketable securities are as follows (dollars in thousands):

	December 31, 2023		December 31, 2022	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 576	$ 530	$ 558	$ 489

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 $83.0 million and $101.8 million as of December 31, 2023 and 2022, respectively.

Debt

The fair values of 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):

	December 31, 2023		December 31, 2022	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,137,534	$ 2,909,301	$ 2,981,481	$ 2,725,606

NOTE 9 – INCOME TAXES

We had no current income tax expense or benefit in 2023 or 2022. We had a deferred income tax expense of $4 thousand in 2023 and deferred income tax benefit of $249 thousand in 2022.

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. In accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. 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. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current portion.

Components of our net deferred tax liability are as follows (dollars in thousands):

	December 31, 2023	December 31, 2022
Deferred tax assets		
Net operating loss carryforwards	$ 192,591	$ 165,636
Operating lease liabilities	94,862	105,039
Deferred revenues and membership withdrawal	4,812	16,028
Safe harbor lease receivables	9,379	8,939
Other	34,171	43,795
	335,815	**339,437**
Less valuation allowance	—	—
	335,815	**339,437**
Deferred tax liabilities		
Basis differences- property, plant and equipment and other	168,948	166,568
Operating lease right-of-use assets	121,125	125,939
Capital credits from other associations	35,638	34,236
Deferred debt prepayment transaction costs	25,327	27,381
Other	—	4,588
	351,038	**358,712**
Net deferred tax liability	**$ (15,223)**	**$ (19,275)**

Net deferred tax liabilities decreased by $4.1 million in 2023 which is deferred and reflected as a decrease in the regulatory asset established for deferred income tax expense. The accounting for regulatory assets is discussed further in Note 2—Accounting for Rate Regulation. The regulatory asset balance associated with deferred income tax expense under the liability method is $15.2 million and $19.3 million at December 31, 2023 and 2022, respectively.

The reconciliation between the statutory federal income tax rate and the effective tax rate is as follows (dollars in thousands):

	2023	2022	2021
Pretax GAAP income at Federal statutory rate	2,118	—	5,435
Pretax GAAP income at State statutory rate, net of federal benefit	282	—	725
Patronage exclusion	(2,401)	—	(6,159)
Asset retirement and environmental reclamation obligations	(6,302)	16,655	10,917
Deferred revenues and membership withdrawal	(11,216)	(22,759)	18,673
Operating liabilities, net of right-of-use assets (1)	(5,281)	(4,919)	1,165
Valuation Allowance	—	—	—
Net operating loss carryforward	26,955	21,034	(27,539)
Other items, net	(4,690)	(9,445)	(2,531)
Impairment	—	—	—
Regulatory treatment of deferred taxes	539	(815)	(391)
Total deferred income tax expense (benefit)	**$ 4**	**$ (249)**	**$ 295**

(1) Net deferred tax liability established as a result of adopting ASC 842. See Note 11 - Leases.

We had an estimated tax loss of $97.6 million for 2023. At December 31, 2023, we have an estimated consolidated federal net operating loss carryforward of $809.2 million of which pre-2018 tax years in the amount of $444.5 million are subject to expiration periods between 2031 and 2037 and $364.7 million have no expiration but are limited to 80 percent of taxable income in the year of utilization. We have $585.5 million of state net operating loss carryforwards, of which $552.4 million is subject to expiration periods between 2030 and 2039 and $33.1 million have no expiration. We did not establish a valuation allowance because it is more likely than not that the benefit from the federal and state net operating losses will be realized in the future.

We file a U.S. federal consolidated income tax return and income tax returns in state jurisdictions where required. The statute of limitations remains open for federal and state returns for the years 2019 forward. We do not have any reserves recorded for uncertain tax positions.

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 funding through the U.S. Department of Agriculture's Empowering Rural America ("New ERA") Program. The New ERA Program implements the $9.7 billion funded in the IRA.

NOTE 10 - 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 forty-two 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 – Members on our consolidated statements of financial position.

Revenue from one Utility Member, United Power, Inc. ("United Power"), was $237.2 million, or 19.6 percent, of our Utility Member revenue and 16.2 percent of our total operating revenues in 2023. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues in 2023.

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):

	2023	2022	2021
Non-member electric sales:			
Long-term contracts	$ 43,087	$ 56,570	$ 44,383
Short-term contracts	102,141	106,785	70,525
Rate stabilization	47,127	95,613	78,457
Provision for rate refunds	94	(51)	(10,196)
Coal sales	13,257	7,021	4,951
Other	53,358	54,399	51,390
Total non-member electric sales and other operating revenue	**$ 259,064**	**$ 320,337**	**$ 239,510**

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 revenue

Rate stabilization represents recognition of income from withdrawal of former Utility Members from membership in us or non-member electric sales revenue that was previously deferred in accordance with accounting requirements related to regulated operations. We recognized $47.1 million of deferred membership withdrawal income for the year ended December 31, 2023, $95.6 million of deferred membership withdrawal income for the year ended December 31, 2022 and $78.5 million of deferred non-member electric sales revenue and deferred membership withdrawal income for the year ended December 31, 2021, as directed by our Board. See Note 2—Accounting for Rate Regulation.

Other operating revenue

Other operating revenue consists primarily of wheeling, transmission and coal sales revenue. Other operating revenue also includes revenue we receive from our Non-Utility Members. Wheeling revenue is received 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. Coal sales revenue results from the sale of coal from the Colowyo Mine and other locations 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.

NOTE 11 – LEASES

Leasing Arrangements as Lessee

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 $2.4 million in 2023 and $2.7 million in 2022. Rent expense is included in operating expenses on our consolidated statements of operations. As of December 31, 2023, there were no arrangements accounted for as finance leases.

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

	December 31, 2023	December 31, 2022
Operating leases		
Operating lease right-of-use assets	$ 9,072	$ 8,784
Less: Accumulated amortization	(2,595)	(2,013)
Net operating lease right-of-use assets	**$ 6,477**	**$ 6,771**
Operating lease liabilities – current	$ (371)	$ (441)
Operating lease liabilities – noncurrent	(1,396)	(1,251)
Total operating lease liabilities	**$ (1,767)**	**$ (1,692)**
Operating leases		
Weighted average remaining lease term (years)	7.0	7.6
Weighted average discount rate	4.68 %	3.87 %

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

Year 1	$	416
Year 2		257
Year 3		202
Year 4		522
Year 5		188
Thereafter		461
Total lease payments	**$**	**2,046**
Less imputed interest		(279)
Total	**$**	**1,767**

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $6.7 million in 2023 and $7.1 million in 2022 are included in other operating revenue on our consolidated statements of operations.

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 13—Variable Interest Entities. However, as the noncontrolling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded. See Note 9—Income Taxes.

NOTE 12 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,120 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan ("RS Plan") except for the 192 employees of Colowyo Coal and any non-bargaining employees hired May 1, 2021 or later and bargaining employees hired July 1, 2021 or later. The RS Plan is a defined benefit pension plan qualified under Section 401(a) and tax-exempt under Section 501(a) of the Internal Revenue Code. It is considered a multiemployer plan under the accounting standards for compensation - retirement benefits. The plan sponsor's Employer Identification Number is 53-116145 and the Plan Number is 333.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits to any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

Our contributions to the RS Plan in each of the years 2023, 2022 and 2021 represented less than 5 percent of the total contributions made each year to the plan by all participating employers. We made contributions to the RS Plan of $31.6, $25.2 and $26.7 million in 2023, 2022 and 2021, respectively.

In December 2012, the National Rural Electric Cooperative Association ("NRECA") approved an option to allow participating cooperatives in the RS Plan to make a contribution prepayment and reduce future required contributions. The prepayment amount is a cooperative's share, as of January 1, 2013, of future contributions required to fund the RS Plan's unfunded value of benefits earned to date using RS Plan actuarial valuation assumptions. The prepayment amount is equal to approximately 2.5 times a cooperative's annual RS Plan required contribution as of January 1, 2013. After making the prepayment, the annual contribution was reduced by approximately 25 percent, retroactive to January 1, 2013. The reduced annual contribution is expected to continue for approximately 15 years. However, changes in interest rates, asset returns, other plan experiences different from expected, plan assumption changes and other factors may have an impact on future contributions and the 15-year period.

In May 2013, we elected to make a contribution prepayment of $71.2 million to the RS Plan. This contribution prepayment was determined to be a long-term prepayment and therefore recorded in deferred charges and amortized beginning January 1, 2013 over the 13-year period calculated by subtracting the average age of our workforce from our normal retirement age under the RS Plan.

Our contributions to the RS Plan include contributions for substantially all of the 215 bargaining unit employees that are made in accordance with collective bargaining agreements. We ceased to add new bargaining employees hired July 1, 2021 or later and non-bargaining employees hired May 1, 2021 or later to the RS Plan.

For the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act ("Act") of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded at both January 1, 2023 and January 1, 2022, based on the Act funding target and the Act actuarial value of assets on those dates.

Because the provisions of the Act do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as part of the actuarial valuation of the plan and may change as a result of plan experience.

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 postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	2023	2022
Executive benefit restoration obligation at beginning of period	$ 8,485	$ 9,852
Service cost	323	468
Interest cost	441	300
Plan amendments - prior service cost	—	308
Curtailment	—	(292)
Benefit payments	—	(110)
Actuarial (gain) loss	909	(2,041)
Executive benefit restoration obligation at end of period	**$ 10,158**	**$ 8,485**
Fair value of plan assets at beginning of year	$ 9,808	$ 8,640
Employer contributions	—	1,734
Benefits paid	—	(109)
Actual return on plan assets	490	(457)
Fair value of plan assets at end of year	**$ 10,298**	**$ 9,808**
Net (asset) liability recognized	**$ (140)**	**$ (1,323)**

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):

	2023	2022
Accumulated other comprehensive loss at beginning of period	$ (2,105)	$ (4,932)
Plan amendments - prior service cost	—	(308)
Amortization of prior service cost into other income	1,156	1,156
Amortization of actuarial loss	219	426
Curtailment and settlement	—	(187)
Unrecognized actuarial gain (loss)	(909)	1,740
Accumulated other comprehensive loss at end of period	**$ (1,639)**	**$ (2,105)**

DEFINED CONTRIBUTION PLANS: We offer one 401(k) plan to all our employees. We contribute 1 percent of employee base salary for all non-bargaining employees hired prior to May 1, 2021. All non-bargaining employees hired May 1, 2021 or later and all bargaining employees hired July 1, 2021 or later are eligible for a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match up to IRS allowed annual maximum. We offer one 401(k) plan to all employees of Colowyo Coal at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions for employees hired prior to May 1, 2021 and provide a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match for employees hired May 1, 2021 or later. All employees are eligible to contribute up to 75 percent of their salary on a pre-tax basis. Under all plans, total 401(k) contributions are not to exceed annual IRS limitations, which are set annually. Employees who have attained age 50 in a calendar year are eligible for the catch-up contribution with maximum contribution limits determined annually by the IRS. We made contributions to the plan of $4.9 million, $3.9 million, and $3.3 million in 2023, 2022, and 2021, respectively.

Effective January 1, 2022 we adopted a 409(a) non-qualified plan. Senior managers, vice presidents and executive officers hired prior to May 1, 2021 are eligible to participate and contribute to the plan, but are not eligible for any employer contribution. Executive officers hired on or after May 1, 2021 will be eligible to participate and contribute to the plan, and are eligible for the employer contribution. The employer contribution is effective once the eligible executive has reached the maximum allowed contribution and employer contribution and match in our base 401(k) plan and includes a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match. We made minimal contributions to the plan in 2022 and 2023.

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 postemployment medical benefits to employees on long-term disability. The plans were unfunded at December 31, 2023, 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 postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	2023	2022
Postretirement medical benefit obligation at beginning of period	$ 2,092	$ 2,809
Interest cost	58	47
Benefit payments (net of contributions by participants)	(469)	(732)
Actuarial gain	(757)	(32)
Postretirement medical benefit obligation at end of period	**$ 924**	**$ 2,092**
Postemployment medical benefit obligation at end of period	243	97
Total postretirement and postemployment medical obligations at end of period	**$ 1,167**	**$ 2,189**

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.

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 comprehensive 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 amount 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 obligation are included in accumulated other comprehensive income as follows (dollars in thousands):

	2023	2022
Amounts included in accumulated other comprehensive income at beginning of period	$ 2,078	$ 3,580
Amortization of prior service credit into other income	(1,637)	(1,636)
Amortization of actuarial loss into other income	(84)	102
Actuarial gain	757	32
Plan amendments	—	—
Amounts included in accumulated other comprehensive income at end of period	**$ 1,114**	**$ 2,078**

The assumptions used in the 2023 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	5.01 %
Initial health care cost trend (2018)	7.25 %
Ultimate health care cost trend	4.50 %
Year that the rate reached the ultimate health care cost trend rate	2034
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	2.61

The following are the expected future benefits to be paid (net of contributions by participants) related to the postretirement medical benefit obligation during the next ten years (dollars in thousands):

2024	$ 360,535
2025	258,005
2026	175,368
2027	99,245
2028	65,168
2029 through 2033	49,246
	$ 1,007,567

NOTE 13 – 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):

	December 31, 2023	December 31, 2022
Net electric plant	$ 703,859	$ 721,997
Noncontrolling interest	134,269	126,180
Long-term debt	206,027	254,876
Accrued interest	5,968	7,400

Our consolidated statements of operations include the following Springerville Partnership expenses (dollars in thousands):

	2023	2022	2021
Depreciation, amortization and depletion	$ 18,138	$ 18,138	$ 18,138
Interest	13,859	17,064	20,038

The revenue and lease expense 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 noncontrolling equity interest in the Springerville Partnership is reflected on our consolidated statements of operations.

NOTE 14 – COMMITMENTS AND CONTINGENCIES

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under contracts that expire between 2024 and 2041. These contracts require us to purchase a minimum quantity of coal at prices subject to escalation reflecting cost increases incurred by the suppliers due to market conditions. The coal purchase projection includes estimated future prices. As of December 31, 2023, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2024	$ 99,241
2025	25,575
2026	14,897
2027	11,866
2028	12,011
Thereafter	77,262
	$ 240,852

Our coal purchases were $119.7 million in 2023, $124.0 million in 2022, and $97.9 million in 2021.

ELECTRIC POWER PURCHASE CONTRACTS: Our largest long-term electric power purchase contracts are with Basin and Western Area Power Administration ("WAPA"). We purchase from Basin power pursuant to two contracts: one relating to all the power which we require to serve our Utility Members' load in the Eastern Interconnection and one relating to fixed scheduled quantities of electric power in the Western Interconnection. Both contracts with Basin continue through December 31, 2050 and are subject to automatic extension thereafter.

We purchase renewable power under long-term contracts, including hydroelectric power from WAPA and from specified renewable generating facilities, including wind, solar and small hydro. We purchase from WAPA power pursuant to three contracts: (i) one contract relating to WAPA's Loveland Area Projects that terminates September 30, 2024 and replaced with one contract that commences delivery on October 1, 2024 and terminates September 30, 2054, and (ii) two contracts relating to WAPA's Salt Lake City Area Integrated Projects that terminate September 30, 2024 and replaced with one contract that commences delivery on October 1, 2024 and terminates September 30, 2057.

As of December 31, 2023, we have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,381 MWs, including 674 MWs of wind-based power purchase contracts and 680 MWs of solar-based power purchase contracts that expire between 2030 and 2042.

Costs under the above electric power purchase contracts were as follows (dollars in thousands):

	2023	2022	2021
Basin	$ 142,456	$ 148,146	$ 146,532
WAPA	74,899	67,791	70,107
Renewables, other than WAPA	78,177	85,601	71,565

ENVIRONMENTAL: As with most electric utilities, we are subject to extensive federal, state and local environmental requirements that regulate, among other things, air emissions, water discharges and the use and management of hazardous and solid wastes. Compliance with these requirements requires significant expenditures for the installation, maintenance and operation of pollution control equipment, monitoring systems and other equipment or facilities.

Our operations are subject to environmental laws and regulations that are complex, change frequently and have historically become more stringent and numerous over time. Federal, state, and local standards and procedures that regulate environmental impact of our operations are subject to change. Consequently, there is no assurance that environmental regulations applicable to our facilities will not become materially more stringent, or that we will always be able to obtain all required operating permits. More stringent standards may require us to modify the design or operation of existing facilities or purchase emission allowances. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of our facilities that are not in compliance, including the shutting down of additional generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled. The cost impact of the implementation of regulation on existing legislation and future legislation or regulation will depend upon the specific requirements thereof and cannot be determined at this time, but it could have a significant effect on our financial condition, results of operations and cash flow.

From time to time, we are alleged to be in violation or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. Additionally, we may need to deal with notices of violation, enforcement proceedings or challenges to construction or operating permits. In addition, we may be involved in legal proceedings arising in the ordinary course of business. However, we believe our facilities are currently in compliance with such regulatory and operating permit requirements.

LEGAL:

FERC Tariff. On September 3, 2019, we became FERC jurisdictional for our Utility Member rates, transmission service, and our market-based rates. We filed our tariff for wholesale electric service and transmission at FERC in December 2019. On March 20, 2020, FERC issued orders regarding tariff filings. FERC's orders generally accepted our tariff filings and recognized that we became FERC jurisdictional on September 3, 2019. FERC also did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered FPA section 206 proceedings to determine the justness and reasonableness of our rates and wholesale electric service contracts. On August 2, 2021, FERC approved our settlement agreement related to our Utility Members stated rate. With the exception of four reserved issues contingent on United Power being a settling party, the settlement resolved all issues set for hearing and settlement procedures related to our Utility Member rates. On March 7, 2022, FERC approved our settlement agreement related to our transmission service rates. On August 15, 2023, FERC issued an order on the four reserved issues related to our Utility Members stated rate.

Petitions for review related to our tariff filings, including our Utility Member rates, were filed with the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court of Appeals") by other parties, including United Power. The last petition for review, 20-1255, related to whether certain of our Board policies are required to be filed with FERC, was dismissed by the D.C. Circuit Court of Appeals on December 28, 2023 after United Power voluntarily filed to dismiss such petition on December 15, 2023.

United Power's Adams District Court Complaint. On May 4, 2020, United Power filed a Complaint for Declaratory Judgement and Damages in the Adams County District Court, 2020CV30649, against us and our three Non-Utility Members.

On July 2, 2021, the court granted United Power's motion to amend its May 2020 complaint to amend its claims as to our three Non-Utility Members and to add a claim that our addition of the Non-Utility Members violated Colorado law.

After the court dismissed some of the claims against us and the Non-Utility Members, the remaining claims included seeking declaratory orders that the addition of the Non-Utility Members violated Colorado law, the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void, and the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula do not apply to United Power and are void, and that we have breached our Bylaws and our wholesale electric service contract with United Power.

On November 1, 2023, we and United Power executed a settlement Term Sheet that was approved by each party’s Board. The parties agreed to a mutual release of claims, and to file a stipulation of dismissal, with prejudice, of the litigation pending in Adams County District Court after the parties executed a formal settlement agreement and other agreements related to power and asset sales to United Power. The parties executed the formal settlement agreement and related agreements on December 8, 2023. On December 11, 2023, the parties filed a joint dismissal of all claims with prejudice, and the court granted the motion and dismissed the lawsuit on December 12, 2023.

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, 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, 22-1169. On August 18, 2022, we filed a motion to intervene with the DC Circuit Court of Appeals and an order granting said motion was issued on September 6, 2022. On January 24, 2023, the parties to the proceeding filed a motion with the court to consolidate this proceeding with other related proceedings with the DC Circuit Court of Appeals and proposed a procedural schedule with final briefings due in October 2023. On March 6, 2023, the DC Circuit Court of Appeals granted the motion to consolidate the proceedings. On October 31, 2023, the final briefs were filed in this consolidated proceeding. The oral arguments were heard on January 17, 2024 and the parties await a decision. 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.

LPEA's La Plata County District Court Complaint. On November 10, 2023, La Plata Electric Association, Inc. ("LPEA") filed a Complaint in the La Plata County District Court, 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. The motion to dismiss is fully briefed and waiting for a court's ruling. It is not possible to predict the outcome of this matter, whether the litigation will be dismissed or 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.

Basin Complaint. On January 12, 2024, Basin filed a complaint with the U.S. District Court District of North Dakota Eastern Division, 3:24-cv-00008-PDW-ARS, against us alleging that the filing of our modified contract termination payment tariff filed with FERC on September 1, 2021 constitutes a breach of our Wholesale Power Contract for the Eastern Interconnection with Basin. The complaint provides that Basin will seek a preliminary and permanent injunction, along with specific performance, that would restrict us from allowing a Utility Member in the Eastern Interconnection from terminating its wholesale electric service contract with us early. On February 1, 2024, Basin filed with the court a motion for preliminary injunction that would enjoin us from disposing of our assets in the Eastern Interconnection in violation of our Wholesale Power Contract for the Eastern Interconnection with Basin. Basin's preliminary injunction seeks to preclude us from allowing a Utility Member in the Eastern Interconnection from terminating its wholesale electric service contract with us prior to the end of 2050. On February 15, 2024, we filed a response to Basin's motion. We disputed much of the merit of Basin's motion, but did not oppose the court granting a limited preliminary injunction. On February 28, 2024, Northwest Rural Public Power District ("NRPPD") filed a motion to intervene in the case that was granted by the court. On March 6, 2024, NRPPD filed a response to Basin's motion seeking for the court to deny Basin’s motion for preliminary injunction. Responses by Basin and us are due by March 20, 2024. It is not possible to predict the outcome of this matter or whether an injunction will be granted or if we will incur any liability in connection with this matter.

NOTE 15 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 15, 2024, which is the date when the financial statements were issued.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this annual 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 as of December 31, 2023, our disclosure controls and procedures were effective, to provide reasonable assurance that information required to be disclosed in our reports under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Management necessarily applies its judgment in assessing the costs and benefits of such controls and procedures that, by their nature, can only provide reasonable assurance regarding management's control objectives.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and Board; and
- provide reasonable assurance that unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements are prevented or detected timely.

Management, including our principal executive officer and principal financial officer, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2023. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013. Based on its evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2023.

Remediation of Previous Identified Material Weakness - Asset Retirement and Environmental Reclamation Obligation Process

As previously disclosed in "Controls and Procedures" in Item 9A of our 2022 Annual Report on Form 10-K, filed with the SEC on March 10, 2023, we identified a material weakness in our controls related to accounting for asset retirement and environmental reclamation obligations for coal mines.

We implemented internal control procedures over the asset retirement and environmental reclamation obligation process, including: (i) established separate accounts for each mine pit in order to segregate each related asset retirement obligation into its own individual account; (ii) established procedures to perform monthly rollforward schedules for each asset retirement and environmental reclamation obligation and utilize those rollforward schedules in the monthly account reconciliation process to identify issues on a more timely basis; (iii) established a calculation model which will only be used for a mine pit in final reclamation in order to more accurately adjust the remaining obligation; (iv) implemented quarterly meetings between management and staff in order to review both the asset retirement and environmental reclamation obligations; and (v) engaged with a third party to evaluate our process and design attributes.

As described above in “Management’s Annual Report on Internal Control Over Financial Reporting”, we concluded that our internal control over financial reporting was effective as of December 31, 2023 based, in part, on the effectiveness of the changed and new controls implemented during 2023 as described above.

Changes in Internal Control over Financial Reporting

Other than as described above in connection with implementation of the remediation action discussed above and the changes in certain controls related to the transition of certain human resource software functions to a new hosted solution, there were no changes that occurred during the fourth quarter ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

On March 12, 2024, we certified the election by our Utility Member, Wheatland Rural Electric Association, of Robert Brockman to replace John "Jack" Finnerty as the director representing them on our Board . Mr. Brockman will serve on the External Affairs-Member Relations Committee.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

Each Member elects one representative to serve on our Board, unless such Member waives or declines representation on our Board. Each Class A member and each Class B member that purchases at least 65 percent of capacity from us elects its representative to serve on our Board, unless such Member waives or declines representation on our Board. United Power, LPEA, MPEI, and our Non-Utility Members have either waived or declined representation on our Board. Each of our directors must be a general manager, director or trustee of such Member. Except as otherwise provided in our Bylaws, the term of each director is from the time he or she is elected by his or her Member, and such election is certified in writing to us by such Member until such Member elects another person to serve and the fact of such election is certified in writing to us by such Member. Each representative on our Board brings an understanding of our Utility Members' business and brings insight to our Utility Members' operations which we believe qualifies them to serve on our Board. The directors on our Board and their ages as of March 1, 2024 are as follows:

NAME	AGE	UTILITY MEMBER - REPRESENTATIVE
Timothy A. Rabon—Chairman and President	63	Otero County Electric Cooperative, Inc.
Donald Keairns—Vice Chairman	64	San Isabel Electric Association, Inc.
Julie Kilty—Secretary	65	Wyrulec Company
Stuart Morgan—Treasurer	77	Wheat Belt Public Power District
Thaine Michie—Assistant Secretary	83	Poudre Valley Rural Electric Association, Inc.
Scott Wolfe—Assistant Secretary	60	San Luis Valley Rural Electric Cooperative, Inc.
Charles Abel II—Executive Committee	55	Sangre de Cristo Electric Association, Inc.
Arthur W. Connell—Executive Committee	70	Central New Mexico Electric Cooperative, Inc.
Douglas Shawn Turner—Executive Committee	62	The Midwest Electric Cooperative Corporation
Leroy Anaya	67	Socorro Electric Cooperative, Inc.
Robert Baca	59	Mora-San Miguel Electric Cooperative, Inc.
Lucas Bear	43	Northwest Rural Public Power District
Robert Bledsoe	74	K.C. Electric Association
Lawrence Brase	77	Southeast Colorado Power Association
Leo Brekel	72	Highline Electric Association
William Bridges	63	Big Horn Rural Electric Company
Robert Brockman	74	Wheatland Rural Electric Association
Matt M. Brown	72	High Plains Power, Inc.
Kevin Cooney	68	San Miguel Power Association, Inc.
Elias Coriz	58	Jemez Mountains Electric Cooperative, Inc.
Mark Daily	71	Gunnison County Electric Association
Jerry Fetterman	68	Empire Electric Association, Inc.
Joel Gilbert	65	Southwestern Electric Cooperative, Inc.
Rick Gordon	70	Mountain View Electric Association, Inc.
Ronald Hilkey	84	White River Electric Association, Inc.
Larry Hoozee	71	Morgan County Rural Electric Association
Joe Hoskins	69	Continental Divide Electric Cooperative, Inc.
Chris Martinez	63	Columbus Electric Cooperative, Inc.
Stanley Propp	77	Chimney Rock Public Power District
Steve M. Rendon	69	Northern Rio Arriba Electric Cooperative, Inc.
Peggy A. Ruble	70	Garland Light & Power Company
Roger L. Schenk	60	Y-W Electric Association, Inc.
Gary Shaw	69	Springer Electric Cooperative, Inc.
Darryl Sullivan	73	Sierra Electric Cooperative, Inc.

Kevin Thomas	66	High West Energy, Inc.
Clay Thompson	65	Carbon Power & Light, Inc.
Wesley Ullrich	67	Roosevelt Public Power District
William Wilson	69	Niobrara Electric Association, Inc.
Phillip Zochol	48	Panhandle Rural Electric Membership Association

Timothy A. Rabon has served on our Board since April 2014 and has been Chairman and President of our Board since August 2021. Prior to serving as Chairman and President of our Board, he served as Vice-Chairman of our Board. He is a member of the Executive Committee, as well as Ex-officio of the Engineering and Operations Committee, the External Affairs-Member Relations Committee, and the Finance and Audit Committee. Mr. Rabon serves as a trustee of Otero County Electric Cooperative, Inc. He is President of Mesa Verde Enterprises, Inc., which is a heavy horizontal civil construction company. He is the Vice President of Heritage Group, which is a commercial and residential land development company. He is also a partner of Mesa Verde Ranch LLP, which is a land holding and cow/calf ranching operation. He is President of Aggregate Technologies, LLC, which is a mining and aggregate production and trucking operation. He is also owner of MV2, LLC, which is a land holding and construction and demolition landfill operation, and Vice President and co-owner of Trabon LLC, which is a trucking and property management company.

Donald Keairns has served on our Board since April 2012 and has been Vice-Chairman of our Board since August 2021. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Keairns serves as a director of San Isabel Electric Association, Inc. He owned and managed several rental properties. Mr. Keairns also serves as a director of Western United Electric Supply Corporation.

Julie Kilty has served on our Board since January 2013 and is Secretary of our Board. She is a member of the Executive Committee and the Finance and Audit Committee. Ms. Kilty serves as President of Wyrulec Company. She is owner of Bar X Ranch, LLC and partner of Bar X Design, LLC.

Stuart Morgan has served on our Board since May 2007 and is Treasurer of our Board. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Morgan serves as a director of Wheat Belt Public Power District. He is President and owner of Morgan Farms, Inc. in Dalton, Nebraska. Mr. Morgan also serves as director of Western States Power Corporation.

Thaine Michie has served on our Board since March 2009 and is Assistant Secretary of our Board. He is a member of the Executive Committee and the Engineering and Operations Committee. Mr. Michie serves as a director of Poudre Valley Rural Electric Association, Inc. He is a retired Chief Executive Officer of Platte River Power Authority.

Scott Wolfe has served on our Board since June 2008 and is Assistant Secretary of our Board. He is a member of the Executive Committee and the Engineering and Operations Committee. Mr. Wolfe serves as director of San Luis Valley Rural Electric Cooperative, Inc. He is a retired farmer and owns Lobo Farm LLC.

Charles Abel II has served on our Board since April 2019. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Abel serves as Treasurer of Sangre de Cristo Electric Association. He is self-employed as a CPA providing tax and financial services to individuals and small businesses. Mr. Abel also serves as a director of CFC.

Arthur W. Connell has served on our Board since July 2000. He is a member of the Executive Committee and the Engineering and Operations Committee. Mr. Connell serves as a trustee of Central New Mexico Electric Cooperative, Inc. and is a rancher.

Douglas Shawn Turner has served on our Board since April 2015. He is a member of the Executive Committee and the Chairman of the Engineering and Operations Committee. Mr. Turner serves as President of The Midwest Electric Cooperative Corporation. He is a farmer and rancher and the owner and operator of Turn-West Farms, Inc. and Wild Horse Spring Land & Cattle Co.

Leroy Anaya has served on our Board since May 2018. He is a member of the External Affairs-Member Relations Committee. Mr. Anaya serves as a trustee of Socorro Electric Cooperative, Inc. He is retired from the Socorro County Assessor's office.

Robert Baca has served on our Board since June 2016. He serves as Chairman of the External Affairs-Member Relations Committee. Mr. Baca serves as Chairman of Mora-San Miguel Electric Cooperative, Inc. He is a self-employed electrician and owner of EGB Electric.

Lucas Bear has served on our Board since August 2020. He is a member of the External Affairs-Member Relations Committee. Mr. Bear serves as a director of Northwest Rural Power District. Mr. Bear is owner and operator of a cow/calf operation.

Robert Bledsoe has served on our Board since July 1998. He is a member of the Finance and Audit Committee. Mr. Bledsoe serves as a director of K.C. Electric Association. He is a self-employed rancher and farmer, half owner of Bledsoe Livestock Co. LLC, and a partial owner of Bledsoe Wind, LLC. Mr. Bledsoe is also on the board of directors of Colorado Rural Electric Association.

Lawrence Brase has served on our Board since April 2018. He is a member of the Finance and Audit Committee. Mr. Brase serves as a director of Southeast Colorado Power Association. He is a retired owner and operator of an independent insurance agency.

Leo Brekel has served on our Board since March 2003. He is a member of the Finance and Audit Committee. Mr. Brekel serves as a director of Highline Electric Association. He is a wheat farmer near Fleming, Colorado. Mr. Brekel also serves as a director of Basin.

William Bridges has served on our Board since June 2020. He is a member of the Engineering and Operations Committee. Mr. Bridges serves as Vice President of Big Horn Rural Electric Company. Mr. Bridges is a civil engineer and owns a consulting firm in Wyoming.

Robert Brockman has served on our Board since March 2024. He is a member of the External Affairs-Member Relations Committee. Mr. Brockman serves as President of Wheatland Rural Electric Association. He is involved in the ownership and operation of a real estate company primarily dealing in farm, ranch, and recreational properties in Wyoming. Mr. Brockman previously served as a director of CFC.

Matt M. Brown has served on our Board since April 2010. He is a member of the Finance and Audit Committee. Mr. Brown serves as Treasurer of High Plains Power, Inc. He is a rancher in Thermopolis, Wyoming.

Kevin Cooney has served on our Board since June 2020. He is a member of the External Affairs-Member Relations Committee. Mr. Cooney serves as a director of San Miguel Power Association Inc. Mr. Cooney is an engineer and is President of Buka Engineering, Inc. and also works for Rolling Energy Resources.

Elias Coriz has served on our Board since August 2023. He is a member of the External Affairs-Member Relations Committee. Mr. Coriz serves as a trustee of Jemez Mountains Electric Cooperative, Inc. He is a security specialist at the Los Alamos National Laboratory in New Mexico and former county commissioner in Rio Arriba County.

Mark Daily has served on our Board since May 2018. He is a member of the Engineering and Operations Committee. Mr. Daily serves as a director of Gunnison County Electric Association. He is a former member service representative for Poudre Valley Rural Electric Association, Inc.

Jerry Fetterman has served on our Board since October 2020. He is a member of the External Affairs-Member Relations Committee. Mr. Fetterman serves as a director of Empire Electric Association Inc. Mr. Fetterman owned and operated Woods Canyon Archaeological Consultants, Inc.

Joel Gilbert has served on our Board since August 2018. He is a member of the Engineering and Operations Committee. Mr. Gilbert serves as President of Southwestern Electric Cooperative, Inc. He is a retired livestock inspector with N.M. Livestock Board. He is currently operating/managing his own ranch.

Rick Gordon has served on our Board since November 1994. He is a member of the Finance and Audit Committee. Mr. Gordon serves as a director of Mountain View Electric Association, Inc. Mr. Gordon owns and operates Gordon Insurance, an independent insurance agency with offices in Calhan, Flagler, Limon and Sterling, Colorado.

Ronald Hilkey has served on our Board since March 2014. He is a member of the Engineering and Operations Committee. Mr. Hilkey serves as a director of White River Electric Association, Inc. Mr. Hilkey is a retired law enforcement officer and the previous owner of Adams Lodge Outfitters.

Larry Hoozee has served on our Board since August 2023. He is a member of the External Affairs-Member Relations Committee. Mr. Hoozee serves as a director of Morgan County Rural Electric Association. He operates his family farm and ranch.

Joe Hoskins has served on our Board since April 2022. He is a member of the External Affairs-Member Relations Committee. Mr. Hoskins serves as a trustee of Continental Divide Electric Cooperative, Inc. He is a retired manager for Maynard Buckles.

Chris Martinez has served on our Board since February 2024. He is a member of External Affairs-Member Relations Committee. Mr. Martinez is the Executive Vice President/General Manager of Columbus Electric Cooperative, Inc. and has served in that position since 2013.

Stanley Propp has served on our Board since April 2015. He is a member of the Engineering and Operations Committee. Mr. Propp serves as a director of Chimney Rock Public Power District. He is a retired farmer and retired shop foreman of Scottsbluff County Weed Control Authority.

Steve M. Rendon has served on our Board since October 2017. He is a member of the Finance and Audit Committee. Mr. Rendon serves as President of Northern Rio Arriba Electric Cooperative, Inc. He is a retired teacher with the Chama Valley Schools.

Peggy A. Ruble has served on our Board since April 2017. She is a member of the Engineering and Operations Committee. Ms. Ruble serves as Vice President of Garland Light & Power Company. She is a retired executive assistant to the Park County Board of County Commissioners in Cody, Wyoming.

Roger L. Schenk has served on our Board since April 2019. He serves as Chairman of the Finance and Audit Committee. Mr. Schenk serves as a director of Y–W Electric Association, Inc. He is owner and operator of a farm.

Gary Shaw has served on our Board since June 2019. He is a member of the Engineering and Operations Committee. Mr. Shaw serves as Secretary of Springer Electric Cooperative, Inc. He is President and owner of Chateau Hill Ranch Company and Chateau Hill Cattle Company.

Darryl Sullivan has served on our Board since December 2013. He is a member of the Engineering and Operations Committee. Mr. Sullivan serves as a trustee of Sierra Electric Cooperative, Inc. He is a farmer and rancher in Monticello, New Mexico. He is a hat maker. He is also a western store owner and owner of Concrete Ditch-Lazer Level.

Kevin Thomas has served on our Board since May 2022. He is a member of the External Affairs-Member Relations Committee. Mr. Thomas serves as a director for High West Energy, Inc. He is a retired school administrator.

Clay Thompson has served on our Board since July 2020. He is a member of the Engineering and Operations Committee. Mr. Thompson serves as a director for Carbon Power & Light, Inc. Mr. Thompson is retired from the USDA Natural Resources Conservation Service and the U.S. Navy Reserve. He owns and operates the family ranch in Laramie, Wyoming.

Wesley Ullrich has served on our Board since April 2023. He is a member of the External Affairs-Member Relations Committee. Mr. Ullrich serves as Secretary of Roosevelt Public Power District. He is a self-employed farmer.

William Wilson has served on our Board since October 2019. He is a member of the External Affairs-Member Relations Committee. Mr. Wilson serves as a director at Niobrara Electric Association, Inc. He is a self-employed cattle rancher and owner of Wilson Ranch.

Phillip Zochol has served on our Board since December 2013. He is a member of the Finance and Audit Committee. Mr. Zochol serves as Vice President of Panhandle Rural Electric Membership Association. He is the assistant manager at Zochol Feedlot LLC.

Audit Committee Financial Expert

We do not have an audit committee financial expert due to our cooperative governance structure and the fact that our Board consists of one representative from our Utility Members. Such representative must be a general manager, director or trustee of such member.

Executive Officers

The following table sets forth the names and positions of our executive officers and their ages as of March 1, 2024:

NAME	AGE	POSITION
Duane Highley	62	Chief Executive Officer
Elda de la Peña	59	Chief Administrative Officer/CHRO
Robert Frankmore	51	Chief of Staff
Barry Ingold	60	Chief Operating Officer
Reginal "Reg" Rudolph	55	Chief Energy Innovations Officer
Jerome "Jay" Sturhahn	51	Senior Vice President, General Counsel
Todd E. Telesz	52	Senior Vice President/Chief Financial Officer

Duane Highley is our Chief Executive Officer and has served in that position since April 2019. Mr. Highley previously served as President and CEO of Arkansas Electric Cooperative Corporation and Arkansas Electric Cooperatives, Inc. and has over 41 years of experience with electric cooperatives. He has a bachelor’s and master’s degree from Missouri University of Science and Technology and completed the Harvard Business School Advanced Management Program. Mr. Highley serves as the co-chair of the Electric Subsector Coordinating Council and is the recipient of the Keystone Policy Center’s 2023 Leadership Award.

Elda de la Peña is our Chief Administrative Officer/CHRO and has served in that position since June 2022. Ms. de la Peña’s title changed from Senior Vice President, People and Culture/Chief Human Resource Officer to her current title when she assumed additional responsibilities including management of information technology. Ms. de la Peña previously served as Senior Manager, Employee Services and has served in numerous human resources roles since joining Tri-State in 1997. She has a master’s degree in language and interpersonal communication and is a SHRM Senior Certified Professional and an HRCI certified Senior Professional in Human Resources.

Robert Frankmore is our Chief of Staff and has served in that position since June 2022. Mr. Frankmore previously served as our Vice President, Strategy. Prior to joining Tri–State in 2014, he served as Senior Vice President at Hill & Knowlton Strategies. Mr. Frankmore has over 21 years of experience in the energy industry and over 26 years of experience in governmental relations, communications and public affairs. He has a Bachelor of Arts degree in political science from Colorado State University.

Barry Ingold is our Chief Operating Officer and has served in that position since June 2022. In June 2022, we consolidated the responsibilities for energy management, generation and transmission into a new Chief Operating Officer position that was filled by Mr. Ingold. Prior to assuming the additional responsibilities for energy management and transmission, he was our Senior Vice President, Generation and had served in that position since 2014. Mr. Ingold informed us that he intends to retire June 2024. Mr. Ingold has served in numerous engineering and management roles since joining Tri-State in 2004. In addition to his 26 years of direct industry experience, Mr. Ingold served for 13 years in the submarine force of the U.S. Navy. He then transitioned to the Navy Reserve where he served for an additional 13 years and attained the rank of Captain prior to retiring from the U.S. Navy. Mr. Ingold has a bachelor’s degree in marine engineering and marine transportation from the U.S. Merchant Marine Academy, a master’s degree in mechanical engineering from the Naval Postgraduate School, and a master’s degree in business administration from Arizona State University.

Reginal "Reg" Rudolph is our Chief Energy Innovations Officer and has served in that position since January 2022. Prior to joining Tri-State, Mr. Rudolph served as General Manager of our Utility Member, San Isabel Electric Association, Inc. for 14 years and has over 32 years of experience in the electric utility industry. Mr. Rudolph has a Master’s of Business Administration degree from Colorado State University and a Bachelor of Business Administration degree from North Dakota State University.

Jerome “Jay” Sturhahn is our Senior Vice President, General Counsel and has served in that position since October 2022. Prior to joining Tri–State, Mr. Sturhahn practiced law in Denver, Colorado as a member at Sherman & Howard L.L.C., including representing us on litigation and regulatory matters. He has a Bachelor of Arts degree from Yale University and a Jurisprudence Doctor degree from the University of Michigan Law School. He has over 21 years of legal experience.

Todd E. Telesz is our Senior Vice President/Chief Financial Officer and has served in that position since January 2024. Mr. Telesz was previously the Chief Executive Officer and General Manager of Basin between 2021 and 2023. Mr. Telesz previously served as senior vice president of the Power, Energy, and Utilities Division of CoBank. Mr. Telesz holds a Bachelor of Science in Economics, with honors, from The Wharton School of the University of Pennsylvania, and serves on several not-for-profit boards of directors.

Code of Ethics

We have a code of ethics policy that applies to our employees including our principal executive officer, principal financial officer and principal accounting officer. A copy of this policy is available on our website, www.tristate.coop.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General Philosophy

Our compensation and benefits program is designed to provide a total compensation package that is competitive within the electric cooperative industry and the geographic areas in which our employees live and work. Our goal is to attract and retain competent personnel and to encourage superior performance by recognition and reward for individual ability and performance.

Total Compensation Package. We compensate our Chief Executive Officer and other executive officers through use of a total rewards package that includes base salary and benefits. Our Chief Executive Officer's base salary is based upon performance and national salary data provided by various surveys, which include data from the labor market for positions with similar responsibilities.

Process. The Executive Committee of our Board recommends on an annual basis the compensation for our Chief Executive Officer to the entire Board and our Board approves such compensation. Our Board has delegated to our Chief Executive Officer the authority to establish and adjust compensation for all other employees. The compensation for all other employees, including executive officers, is determined by the Chief Executive Officer based upon performance and market-based salary data.

Base Salaries. As an electric cooperative, we do not have publicly traded stock and as a result do not have equity-based compensation programs. For this reason, substantially all of our monetary compensation to our executive officers is provided in the form of base salary. We provide our executive officers with a level of cash compensation in the form of base salary that is commensurate with the duties and responsibilities of their positions as well as job performance. These salaries are determined based on market data for positions with similar responsibilities.

Bonuses. As a general practice, we do not normally issue bonuses. However, on occasion, a discretionary cash bonus may be awarded by the Chief Executive Officer to the executive officers or other employees. Our Board has the authority to award a bonus to the Chief Executive Officer if deemed appropriate.

Retention Agreements. The Chief Executive Officer, with the approval of our Board, has in the past executed retention agreements for certain executive officers and other staff as deemed appropriate from time to time. We currently have no retention agreements with our executive officers.

Retirement Plans

Defined Benefit Plan. We participate in the RS Plan, a noncontributory, defined benefit, multiemployer master pension plan which is available to all of our non-bargaining employees hired prior to May 1, 2021 and all bargaining employees hired prior to July 1, 2021. This plan is a qualified pension plan under IRC Section 401(a). Benefits, which accrue under the plan, are based upon the employee's annual base salary as of November 15 of the previous year, their years of benefit service and the plan multiplier.

401(k) Plans. We offer one 401(k) plan to all of our employees. We contribute 1 percent of employee base salary for all non-bargaining employees hired prior to May 1, 2021. All non-bargaining employees hired May 1, 2021 or later and all bargaining employees hired July 1, 2021 or later are eligible for a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match up to IRS allowed annual maximum.

We offer one 401(k) plan to all employees of Colowyo Coal at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions for employees hired prior to May 1, 2021 and provide a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match for employees hired May 1, 2021 or later.

All employees are eligible to contribute up to 75 percent of their salary on a pre-tax basis. Under all plans, total 401(k) contributions are not to exceed annual IRS limitations which are set annually. Employees who have attained age 50 in a calendar year are eligible for the catch-up contribution with maximum contribution limits determined annually by the IRS.

NRECA Pension Restoration Plan and Executive Benefit Restoration Plan. 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 with a hire date prior to May 1, 2021. 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 either 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 RS Plan. The funds for the NRECA Executive Benefit Restoration Plan are held in trust by a third-party bank, and the funds are subject to claims by our creditors in the event of insolvency. Employees hired May 1, 2021 or later are not eligible for either plan.

Executive Deferred Compensation Plan. We offer a non-qualified executive deferred compensation plan for an eligible group of highly compensated employees, which includes all executive employees. Eligible employees can contribute up to 30 percent of their salary on a pre-tax basis. Executive employees hired May 1, 2021 or later who are not eligible for the RS Plan, the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan are eligible for a 10 percent contribution from us to the executive deferred compensation plan.

Perquisites and Other Benefits

The Chief Executive Officer and the other executive officers receive the same health and welfare benefit plans and sick time as all employees. In addition to these benefits, they also receive the following:

- Company vehicle or monthly auto allowance: the Chief Executive Officer and other executive officers are provided their choice of a company vehicle for both business and personal use or a monthly stipend as an auto allowance. There are no restrictions on usage for company vehicles. If a company vehicle is provided, these vehicles are considered compensation, which is grossed up for income taxes. If an executive elects the monthly auto allowance, it is paid monthly and grossed up for income taxes.

- Vacation: Executive officers currently accrue vacation at the rate of six weeks per year. They may accrue up to a maximum of 1,040 hours of vacation.

Compensation Committee Report

The Executive Committee serves as the compensation committee of our Board and has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussion, has recommended to our Board its inclusion in this annual report on Form 10-K.

Executive Committee Members:

Timothy A. Rabon
Donald Keairns
Julie Kilty
Stuart Morgan
Thaine Michie
Scott Wolfe
Charles Abel II
Arthur W. Connell
Douglas Shawn Turner

Compensation Committee Interlocks and Insider Participation

As described above, the Executive Committee of our Board recommends the compensation for our Chief Executive Officer to the entire Board and our Board approves the compensation. Our Board has delegated to our Chief Executive Officer the authority to establish and adjust compensation for all other employees other than himself. Timothy A. Rabon, Donald Keairns, Julie Kilty, Stuart Morgan, Thaine Michie, Scott Wolfe, Charles Abel II, Arthur W. Connell, and Douglas Shawn Turner serve as members of the Executive Committee.

Other than as noted below, no member of the Executive Committee is, or previously was, an officer or employee of us. Mr. Rabon is our Chairman and President, Mr. Keairns is our Vice Chairman, Ms. Kilty is our Secretary, Mr. Morgan is our Treasurer, Mr. Michie is our Assistant Secretary, and Mr. Wolfe is our Assistant Secretary. All of the members of our Executive Committee are directors of our Utility Members. Each of our Utility Members has a wholesale electric service contract with us and we received revenue from each of our Utility Members in excess of $120,000 in 2023.

Executive Compensation

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our principal executive officer, principal financial officer and our three other most highly paid executive officers (based on total compensation for 2023). The table also identifies the principal capacity in which each of these executives serves or served.

Name and Title	Year	Salary	Change in pension value and nonqualified deferred compensation earnings	All other compensation (2)	Total
Duane D. Highley	2023	$ 1,555,645	$ 0 (1)	$ 60,393	$ 1,616,038
Chief Executive Officer	2022	1,489,353	1,822,524	65,565	3,377,442
	2021	1,421,924	2,213,191	65,068	3,700,183
Patrick L. Bridges (3)	2023	559,268	66,384	65,623	691,275
Senior VP/CFO	2022	527,763	168,151	63,116	759,030
	2021	502,770	0 (3)	62,780	565,550
Jerome Sturhahn (4)	2023	724,019	39,243	108,217	871,479
Senior VP, General Counsel	2022	139,423	6,417	12,468	158,308
Barry Ingold	2023	586,747	0 (1)	50,617	637,364
Chief Operating Officer	2022	497,524	464,036	38,321	999,881
	2021	402,217	464,036	39,236	905,489
Reginal Rudolph (5)	2023	458,862	14,613	84,717	558,192
Chief Energy Innovations Officer	2022	400,318	14,975	93,847	509,140

(1) For our Chief Executive Officer and Chief Operating Officer, the lump sum value of the RS Plan decreased by $317,547 and $281,755, respectively, from 2022 to 2023.

(2) Includes retention agreement payments, if applicable, monthly auto allowance or personal use of auto which is grossed up to cover taxes, relocation benefits, employer 401(k) and non-qualified executive plan contribution, group term life, and employer paid premium for medical and dental insurance.

(3) Mr. Bridges quasi-retired on January 6, 2021 from the RS Plan at which time the benefit calculation started over on January 7, 2021. Therefore, the change in value of the plan from December 31, 2020 to December 31, 2021 was a negative $1,014,386.63. Mr. Bridges retired on March 8, 2024. Effective January 29, 2024, Todd Telesz became an employee and our Senior Vice President, Chief Financial Officer.

(4) Mr. Sturhahn became an employee and our General Counsel on October 17, 2022, and is not eligible for the RS Plan. He is eligible for the executive non-qualified deferred compensation plan.

(5) Mr. Rudolph became an employee and our Chief Energy Innovations Officer on January 17, 2022, and is not eligible for the RS Plan. He is eligible for the executive non-qualified deferred compensation plan.

Defined Benefit Plan

As described above, executive employees with a hire date prior to May 1, 2021 are eligible for the RS Plan and participate in either the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan. The following table lists the estimated values under the RS Plan and both restoration plans as of December 31, 2023. As a result of changes in

Internal Revenue Service regulations, the annual base salary used in determining benefits is limited to $305,000 effective January 1, 2023.

Name	Number of years Credited Service as of December 31, 2023	RS Plan Present Value of Accumulated Benefit as of December 31, 2023	Pension Restoration Plans Present Value of Accumulated Benefit as of December 31, 2023	Payments During 2023
Duane D. Highley (1)	4 years, 9 months	$ 3,374,218	$ 5,494,498	None
Patrick L. Bridges (2)	2 years, 11 months	235,492	1,034,420	None
Barry Ingold	18 years	1,838,097	617,851	None

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(1) Mr. Highley began employment with us on April 1, 2019. He has 4 years 9 months of service with us and a total of 39 years and 6 months in the RS Plan due to prior years of participation at previous employers. His participation in the NRECA Executive Benefit Restoration Plan started new on April 1, 2019.

(2) Patrick Bridges received a quasi-retired lump sum on January 6, 2021 from the RS Plan. On January 7, 2021, Mr. Bridges began accruing a new pension plan benefit. Number of years credited for the Pension Restoration Plan is 16 years, 3 months.

The pension benefits indicated above are the estimated amounts payable by the plan, and they are not subject to any deduction for Social Security or other offset amounts. The participant's annual pension at his or her normal retirement date, currently age 62, is equal to the product of his or her years of benefit service multiplied by the average of his or her highest annual salary in five of the last ten years multiplied by 1.9 percent. The value listed in the table is the actual lump sum value that would have been payable to the employee if they had terminated employment on December 31, 2023.

Non-Qualified Executive Deferred Compensation Plan

As described above, executive employees hired May 1, 2021 or later who are not eligible for the RS Plan are eligible for the non-qualified executive deferred compensation plan. The following table lists the contributions during the last fiscal year and balance as of December 31, 2023 for this plan.

Name	Executive contributions in last fiscal year	Our contributions in last fiscal year (1)	Aggregate earnings in last fiscal year	Aggregate withdraws/ distributions	Aggregate balance as of December 31, 2023
Jerome Sturhahn	$ 27,783	$ 39,243	$ 4,891	None	$ 78,347
Reginal Rudolph	0	14,613	3,999	None	33,635

(1) Our non-qualified executive plan contributions are included in the all other compensation in the Summary Compensation Table above for these individuals.

As described above, the above individuals are eligible for a 10 percent contribution from us to the executive deferred compensation plan.

Potential Payments upon Termination

Severance Agreements. As a general practice, we normally do not provide severance packages to employees. However, on occasion, as part of hiring a new employee, we may provide a severance package. Our Chief Energy Innovation Officer, Mr. Rudolph, has a severance package equal to one year of salary and one year of COBRA benefit premiums if his employment ends prior to September 16, 2026 unless the termination was for cause or Mr. Rudolph resigns from us. If Mr. Rudolph were to have been entitled to such severance payment as of December 31, 2023, it would have been a lump sum payment of $502,269.88.

Chief Executive Officer Pay Ratio

The 2023 compensation disclosure ratio of the median annual total compensation of all our employees to the annual total compensation of our Chief Executive Officer is as follows:

Category and Ratio	2023 Total Compensation (1)
Median annual total compensation of all employees (excluding Chief Executive Officer)	$ 157,003
Annual Total Compensation of Duane D. Highley, Chief Executive Officer	1,616,038
Ratio of the median annual total compensation of all employees to the annual total compensation of Duane D. Highley, Chief Executive Officer	1.0:10.29

(1) Includes change in pension value from 2022 to 2023 and if the change was negative, zero was used in the calculation.

In determining the median employee, a listing was prepared of all active employees of us and our subsidiaries as of December 31, 2023. We did not make any assumptions, adjustments, or estimates with respect to total compensation, and we did not annualize the compensation for any full-time employees that were not employed by us for all of 2023. We determined the compensation of our median employee by (1) utilizing the W-2 Box 5 wages for all active employees for 2023 and (2) ranking the annual total compensation of the employees, except the Chief Executive Officer, from lowest to highest. To determine if a material difference exists in the total compensation of the median employee compared to other employees when adding the change in pension value for the employee, we added this value to the median employee and to the three employees below and three employees above. After completing this evaluation of the seven employees, it was determined there was not a material difference in the pension value of the years of benefit service of the seven employees. Therefore, we did not change the median employee after adding the change in pension value to be the median employee of the above mentioned seven employees.

After identifying the median employee, we calculated annual total compensation for such employee using the same methodology we use for our named executive officers as set forth in the above Summary Compensation Table.

Our Chief Executive Officer Pay Ratio is a reasonable estimate calculated in a manner consistent with Item 402(u) of Regulation S-K. However, due to the flexibility afforded by Item 402(u) of Regulation S-K in calculating the Chief Executive Officer Pay Ratio, our Chief Executive Officer Pay Ratio may not be comparable to the Chief Executive Officer pay ratios presented by other companies.

Board of Directors Compensation

Chairman and President of our Board

The Chairman and President of our Board is compensated per Board policy as follows:

1) Due to the duties and responsibilities of the Chairman and President, the allowance paid to the Chairman and President is $160,000 per year paid on a bi-weekly basis. The Chairman and President is also reimbursed for expenses submitted as incurred.

2) The Chairman and President is assigned a company vehicle for business and personal use.

Board of Directors

Our Board, excluding the Chairman and President, are compensated per Board policy as follows:

1) A director will receive a monthly preparation fee of $500.

2) For each day a director attends one or more authorized meetings or events in person, including virtual meetings, the director is entitled to an attendance allowance of $500. For virtual meetings or virtual events that require an hour or less of director time, no allowance will be paid without approval from the Chairman and President or Vice Chairman.

3) The travel day allowance for travel time for directors going to and from the above meetings or events, where one or more days or a partial day of travel is required in addition to the day of the meeting, is up to $500 with the allowance based upon the number of miles the director lives from the location of the meeting.

4) Directors are reimbursed for transportation in connection with the foregoing meetings or events at the published maximum IRS approved mileage rate for use of a personal vehicle, or for the actual commercial plane, bus, rail, rental car and/or ground transportation fares incurred.

5) The allowance for meal expenses of a director incurred in the Denver metropolitan area in connection with attendance at meetings is at the published maximum IRS allowable per diem rate, for the Denver metropolitan area. A director may stay at a hotel approved by us, the Chairman and President, or the Executive Committee in the Denver metropolitan area in connection with attendance at meetings at no charge to the director. All meetings attended by directors outside of the Denver metropolitan area will be reimbursed for actual receipted expenses for meals and lodging incurred at such meetings.

Directors are authorized to attend other meetings or functions at our expense only with the authorization of our Board or the Chairman and President, or in the absence of those, with the authorization of the Vice Chairman upon consultation with and consent of any member of the Executive Committee.

Directors' Deferred Compensation Plan

Our Board, including the Chairman and President of our Board, are eligible to participate in the Directors' Elective Deferred Fees Plan. This plan allows for deferral of director's fees into an unfunded and unsecured plan under Section 409A of the Internal Revenue Code. Under this plan, the funds are held in trust by a third-party bank and the funds are subject to claims by our creditors in the event of insolvency.

Board of Directors Compensation Table

The following table sets forth information concerning fees earned or paid to our Board in 2023 for services rendered. Director fees are earned or paid in cash after submission of receipts to us. Directors are also reimbursed for expenses as described above.

Name	2023 Board Fees (1)
Charles Abel II	$ 22,000
Leroy Anaya	27,875
Robert Baca	30,000
Lucas Bear	20,125
Robert Bledsoe	27,750
Lawrence Brase	22,000
Leo Brekel	13,500
William Bridges	33,000
Matt M. Brown	18,000
Arthur W. Connell	36,000
Kevin Cooney	24,000
Elias Coriz	7,375
Mark Daily	17,000
Steven Douglas (2)	4,375
Raymond Bruce Duran (2)	22,500
Jerry Fetterman	20,000
John "Jack" Finnerty	15,375
Joel Gilbert	19,625
Rick Gordon	19,000
Randolph "Randy" Graff (2)	12,625
Ronald Hilkey	17,500
Ralph Hilyard (2)	4,250
Larry Hoozee	8,250
Joe Hoskins	26,500
Donald Keairns	56,750
Hal Keeler	17,500
Julie Kilty	28,000
Brian McCormick (2)	7,500
Kohler McInnis (2)	27,250

Thaine Michie	24,000
Stuart Morgan	29,250
Stanley Propp	21,000
Timothy A. Rabon	160,096
Steve M. Rendon	26,875
Peggy A. Ruble	23,000
Roger L. Schenk	23,250
Gary Shaw	19,750
Darryl Sullivan	9,800
Kevin Thomas	20,250
Clay Thompson	17,250
Carl Trick II (2)	9,000
Douglas Shawn Turner	24,750
Wesley Ulrich	11,250
William Wilson	25,500
Scott Wolfe	20,000
Phillip Zochol	18,000

(1) Various directors have deferred a total of $13,300 of the actual Board fee payments made in 2023.

(2) Individual ceased serving on our Board prior to December 31, 2023.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

Because we are a cooperative, our Members own us. Each of our directors, as required by our Bylaws, is a general manager, director or trustee of the Utility Member that it represents on our Board. Each of our Utility Members has a wholesale electric service contract with us and we received revenue from each of our Utility Members in excess of $120,000 in 2023.

Chris Martinez is the Executive Vice President/General Manager of Columbus Electric Cooperative, Inc. and has served as a director on our Board since February 2024. Columbus Electric Cooperative, Inc. is a Utility Member and our revenue from them under our wholesale electric service contract was $8.4 million, or 0.7 percent, of our Utility Member revenue and 0.6 percent of our total operating revenue in 2023.

Other than as described above, in 2023, we had no transactions with any related persons that exceeded $120,000 and there are currently no proposed transactions with any related persons that exceed $120,000.

Our Board has adopted a conflicts of interest policy that sets forth guidelines for the approval of any related party transaction and requires that our directors, senior management, and certain employees annually report and supplement as needed to the Chairman and President of our Board all personal and business relationships that could influence decisions related to our operation and management, as well as any relationships that could give the appearance of influencing such decisions.

Director Independence

Because we are a cooperative, our Members own us. Our Bylaws set forth the specific requirements regarding the composition of our Board. See "DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE –Directors" for a description of these requirements.

In addition to meeting the requirements set forth in our Bylaws, all directors satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet all the requirements set forth in our Bylaws. Although we do not have any securities listed on the NASDAQ Stock Market, we have used its independence criteria to make this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table presents fees for services provided by our independent registered accounting firm, Ernst & Young LLP, for the two most recent fiscal years.

	2023	2022
Audit Fees(1)	$ 868,000	$ 780,000
Audit-Related Fees(2)	—	—
Tax Fees(3)	33,500	27,000
All Other Fees(4)	—	—
Total	$ 901,500	$ 807,000

(1) Audit of annual consolidated financial statements and review of interim consolidated financial statements included in SEC filings and services rendered in connection with financings, including comfort letters, consents, and comment letters. Also includes audit of the financial statements included in the annual FERC Form 1 filing.

(2) Other audit-related services generally relate to accounting consultations pertaining to accounting standards impacting future periods. There were no such services or related fees during 2022 and 2023.

(3) Professional tax services including tax consulting and tax return compliance.

(4) All other fees.

For the two most recent fiscal years, other than those fees listed above, we did not pay Ernst & Young LLP any fees for any other products or services.

Pre-Approval Policy

All audit, tax, and other services, and related fees, to be performed by Ernst & Young LLP for us must be reviewed by the Finance and Audit Committee and approved by our Board. In the event that time does not allow for Finance and Audit Committee review and Board pre-approval of non-audit fees, non-audit service may be performed by Ernst & Young LLP if pre-approved by both the Chairman and the Vice-Chairman of the Finance and Audit Committee. The Finance and Audit Committee reviews the description of the services and an estimate of the anticipated costs of performing those services for approval by our Board. Committee review and Board pre-approval is granted usually at regularly scheduled meetings. During 2022 and 2023, all services performed by Ernst & Young LLP were approved or pre-approved in accordance with this policy.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) **List of Documents Filed as a Part of This Report.**

1. Financial Statements

   See Index to Financial Statements under Part II, Item 8

2. Financial Statements Schedules

   Not Applicable

3. Exhibits

Exhibit Number	Description
3.1†	Amended and Restated Articles of Incorporation of Tri-State Generation and Transmission Association, Inc. (Filed as Exhibit 3.1 to the Registrant's Form 10-K filed on March 5, 2021, File No. 333-212006.)
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc., dated August 5, 2021 (Filed as Exhibit 3.2 to the Registrant's Form 10-Q filed on November 10, 2021, File No. 333-212006.)
4.1†	Indenture, dated effective as of December 15, 1999, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association, as (successor) trustee, as supplemented by Supplemental Indenture No. 2, dated June 30, 2000, Supplemental Indenture No. 20, dated July 30, 2009, Supplemental Indenture No. 21, dated October 8, 2009, Supplemental Indenture No. 27, dated July 29, 2011, Supplemental Indenture No. 28, dated March 15, 2012, Supplemental Indenture No. 29, dated December 6, 2012, Supplemental Indenture No. 30, dated July 3, 2013, Supplemental Indenture No. 34, dated October 30, 2014 and Supplemental Indenture No. 38, dated November 21, 2014 (Filed as Exhibit 4.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.1.1†	Supplemental Master Mortgage Indenture No. 39, dated and effective as of May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.1.2†	Supplemental Master Mortgage Indenture No. 40, dated and effective as of November 16, 2017, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1.2 to the Registrant's Form 10-K filed on March 9, 2018, File No. 333-203560.)
4.1.3†	Supplemental Master Mortgage Indenture No. 41, dated and effective as of April 25, 2018, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on April 25, 2018, File No. 333-203560.)
4.1.4†	Supplemental Master Mortgage Indenture No. 42, dated and effective as of December 11, 2018, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1.4 to the Registrant's Form 10-K filed on March 8, 2019, File No. 333-212006.)
4.1.5†	Supplemental Master Mortgage Indenture No. 43, dated and effective as of June 24, 2020, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1.5 to the Registrant's Form 10-Q filed on August 12, 2020, File No. 333-212006.)
4.1.6†	Supplemental Master Mortgage Indenture No. 44, dated and effective as of April 25, 2022, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on April 25, 2022, File No. 333-212006.)
4.1.7	Supplemental Master Mortgage Indenture No. 46, dated and effective as of December 19, 2023, between Tri-State Generation and Transmission Association, Inc. and U.S. Bank Trust Company, National Association as (successor) trustee

4.2†	Exchange and Registration Rights Agreement, dated October 30, 2014, between Tri-State Generation and Transmission Association, Inc. and Goldman, Sachs & Co. (Filed as Exhibit 4.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.3†	Form of Exchange Bond for 3.70% First Mortgage Bonds, Series 2014E-1, due 2024 (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.4†	Form of Exchange Bond for 4.70% First Mortgage Bonds, Series 2014E-2, due 2044 (Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.5†	Exchange and Registration Rights Agreement, dated May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, U.S. Bancorp Investments, Inc. and Wells Fargo Securities, LLC (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.6†	Form of Exchange Bond for 4.25% First Mortgage Bonds, Series 2016A, due 2046 (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement, File No. 333-212006.)
4.7.1*	Term Loan Agreement, dated December 6, 2012, between Tri-State and CoBank, ACB
4.7.2*	Secured Promissory Note, dated December 6, 2012, from Tri-State to CoBank, ACB, related to Loan No. 002660317, in the original amount of $100,000,000
4.8.1*	Term Loan Agreement, dated October 31, 2014, between Tri-State and CoBank, ACB
4.8.2*	First Amendment to Term Loan Agreement, dated May 25, 2023, between Tri-State and CoBank, ACB
4.8.3*	Promissory Note, dated November 4, 2014, from Tri-State to CoBank, ACB, related to term loan A 002847868, in the original amount of $68,345,000
4.8.4*	Promissory Note, dated November 4, 2014, from Tri-State to CoBank, ACB, related to term loan B 002847716, in the original amount of $102,220,000
4.9.1*	Term Loan Agreement, dated December 11, 2018, between Tri-State and CoBank, ACB
4.9.2*	First Amendment to Term Loan Agreement, dated May 25, 2023, between Tri-State and CoBank, ACB
4.9.3*	Promissory Note, dated December 11, 2018, from Tri-State to CoBank, ACB, related to term loan A 003170483, in the original amount of $55,180,926
4.9.4*	Promissory Note, dated December 11, 2018, from Tri-State to CoBank, ACB, related to term loan B 003170567, in the original amount of $69,819,074
4.10.1*	Term Loan Agreement, dated June 24, 2020, between Tri-State and CoBank, ACB
4.10.2*	First Amendment to Term Loan Agreement, dated May 25, 2023, between Tri-State and CoBank, ACB
4.10.3*	Promissory Note, dated June 24, 2020, from Tri-State to CoBank, ACB, related to term loan No. 30080493, in the original amount of $125,000,000
4.11.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.11.2*	First Amendment to Loan Agreement, dated March 6, 2023, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.11.3*	Secured Promissory Note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to Loan C-0047-9077, in the original amount of $102,220,000
4.12.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.12.2*	Secured Promissory Note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9078, in the original amount of $68,300,000
4.13.1*	Loan Agreement, dated June 24, 2020, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.13.2*	First Amendment to Loan Agreement, dated March 6, 2023, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.13.3*	Secured Promissory Note, dated June 24, 2020, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-A-9080, in the original amount of $50,000,000
4.13.4*	Secured Promissory Note, dated June 24, 2020, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-A-9081, in the original amount of $50,000,000
4.14*	Amended and Restated Bond, dated October 2, 2017, pursuant to the Trust Indenture, dated February 1, 2009, between Moffat County, Colorado and U.S. Bank Trust Company, National Association, as (successor) trustee, in the original amount of $46,800,000 related to Pollution Control Refunding Revenue Bonds, Series 2009B.

4.15.1*	Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement
4.15.2*	Notes, dated December 12, 2017, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement
4.15.3*	Notes, dated April 12, 2018, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement
4.16*	Note, dated October 21, 2003, from Springerville Unit 3 Holding to Wilmington Trust Company, relating to Tri-State 2003-Series B Pass Through Trust, in the original amount of $405,000,000, due in 2033
4.17.1*	Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of $400,000,000
4.17.2*	Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of $100,000,000
4.18*	Multiple Advance Term Loan Agreement, dated as of March 24, 2023, among Tri-State, as borrower, each lender from time to time party thereto, including CoBank, ACB, as administrative agent
4.18.1*	Secured Promissory Note, dated March 24, 2023, from Tri-State to CoBank ACB, as administration agent, relating to Multiple Advance Term Loan Agreement, in the original amount of $150,000,000
10.1†	Second Amended and Restated Wholesale Power Contract for the Eastern Interconnection, dated as of September 27, 2017, between Tri-State and Basin Electric Power Cooperative (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on September 28, 2017, File No. 333-212006.)
10.2†	Wholesale Power Contract for the Western Interconnection, dated as of September 27, 2017, between Tri-State and Basin Electric Power Cooperative (Filed as Exhibit 10.2 to the Registrant's Form 8-K filed on September 28, 2017, File No. 333-212006.)
10.3†	Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, executed on various dates during the months of September, November and December, 1975, taking effect as of May 25, 1977, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, Heartland Consumer Power District, Wyoming Municipal Power Agency, and Western Minnesota Municipal Power Agency, as amended by Amendment No. 1, dated as of March 15, 1977, Amendment No. 2, dated as of March 16, 1977, Amendment No. 3, dated as of August 1, 1982, Amendment 4, dated as of September 1, 1982, Amendment No. 5, dated as of May 2, 1983, Amendment No. 6, dated as of March 1, 1986, Amendment No.7, dated as of September 15, 1986, Amendment No. 8, dated as of June 10, 1997, Amendment No. 9, dated as of April 16, 1999, and Amendment No. 10, dated as of July 31, 2014 (Filed as Exhibit 10.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.3.1†	Amendment No. 12 to Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, dated as of September 20, 2018, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, Heartland Consumer Power District, Wyoming Municipal Power Agency, and Western Minnesota Municipal Power Agency (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on September 26, 2018, File No. 333-203560.)
10.3.2†	Amendment No. 13 to Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, dated as of May 27, 2021, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, Wyoming Municipal Power Agency, and Western Minnesota Municipal Power Agency (Filed as Exhibit 10.3.2 to the Registrant's Form 10-Q filed on August 9, 2021, File No. 333-203560.)
10.3.3†	Amendment No. 14 to Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, dated as of May 1, 2023, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, and Western Minnesota Municipal Power Agency (Filed as Exhibit 10.3.3 to the Registrant's Form 10-Q filed on May 8, 2023, File No. 333-203560.)
10.4†	Wholesale Electric Service Contract, dated July 1, 2007, between Tri-State and Big Horn Rural Electric Company, together with a schedule identifying 41 other substantially identical Wholesale Electric Service Contracts (Filed as Exhibit 10.4 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.5†	Participation Agreement, dated as of October 21, 2003, among Tri-State, as Construction Agent and as Lessee, Computershare Trust Company, N.A., as (successor) Independent Manager, Springerville Unit 3 Holding LLC, as Owner Lessor, Springerville Unit 3 OP LLC, as Owner Participant, and Wilmington Trust Company, as Series A Pass Through Trustee and Series B Pass Through Trustee and as Indenture Trustee (Filed as Exhibit 10.5 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.5.1†	First Amendment to Participation Agreement, effective as of July 1, 2022, among Tri-State, as Construction Agent and as Lessee, Computershare Trust Company, N.A., as (successor) Independent Manager, Springerville Unit 3 Holding LLC, as Owner Lessor, Springerville Unit 3 OP LLC, as Owner Participant, and Wilmington Trust Company, as Indenture Trustee (Filed as Exhibit 10.5.1 to the Registrant's Form 10-K filed on March 10, 2023, File No. 333-203560).
10.6.1†	Supplemental Master Mortgage Indenture No. 23, dated as of June 8, 2010, between U.S. Bank Trust Company, National Association, as (successor) trustee, and Tri-State in connection with Series 2010A Secured Obligations (Filed as Exhibit 10.6.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.6.2†	Supplemental Master Mortgage Indenture No. 24, dated as of October 8, 2010, between U.S. Bank Trust Company, National Association, as (successor) trustee, and Tri-State in connection with reopening and amending of Series 2010A Secured Obligations (Filed as Exhibit 10.6.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.7†	2014 Note Purchase Agreement, dated as of October 31, 2014, between Tri-State and various purchasers of the notes identified therein (Filed as Exhibit 10.8 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.8†	Amended and Restated Credit Agreement, dated as of April 25, 2022, amongst Tri-State, as borrower, each lender from time to time party thereto, including National Rural Utilities Cooperative Finance Corporation, as administrative agent (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on April 25, 2022, File No. 333-203560.)
10.8.1†	Amendment No. 1 to Amended and Restated Credit Agreement, dated as of June 15, 2023, amongst Tri-State, as borrower, each lender from time to time party thereto, including the National Rural Utilities Cooperative Finance Corporation, as administrative agent (Filed as Exhibit 10.8.1 to the Registrant's Form 10-Q filed on August 10, 2023, File No. 333-203560.)
10.9†	Form of Commercial Paper Dealer Agreement between Tri-State, as issuer, and the Dealer party thereto (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on May 13, 2016, File No. 333-203560.)
10.9.1†	Form of First Amendment to Commercial Paper Dealer Agreement between Tri-State, as issuer, and the Dealer party thereto (Filed as Exhibit 10.10.1 to the Registrant's Form 10-Q filed on August 9, 2021, File No. 333-203560.)
10.10†	Membership Withdrawal Agreement, between Tri-State and United Power, Inc., filed unexecuted with the Federal Energy Regulatory Commission on January 31, 2024 (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on February 1, 2024, File No. 333-203560.)
10.11†	Membership Withdrawal Agreement, between Tri-State and Northwest Rural Public Power District, filed unexecuted with the Federal Energy Regulatory Commission on February 27, 2024 (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on February 28, 2024, File No. 333-203560.)
10.12**†	Directors' Elective Deferred Fees Plan, effective January 1, 2005, executed December 11, 2008 (Filed as Exhibit 10.10 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.13**†	Executive Benefit Restoration Plan, dated December 12, 2014, as amended by Amendment effective July 30, 2020 (Filed as Exhibit 10.2 to the Registrant's Form 10-K filed on March 5, 2021, File No. 333-212006.)
10.13.1**†	Executive Benefit Restoration Plan of Tri-State Generation and Transmission Association, Inc. - Amendment No. 2, effective May 1, 2021 (Filed as Exhibit 10.12.1 to the Registrant's Form 10-Q filed on May 7, 2021, File No. 333-203560.)
10.14**†	Amended and Restated Pension Restoration Plan of Tri-State Generation and Transmission Association, Inc., dated December 12, 2014 (Filed as Exhibit 10.19 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
21.1	Subsidiaries of Tri-State Generation and Transmission Association, Inc.
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 Patrick L. Bridges (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 Patrick L. Bridges (Principal Financial Officer).
95	Mine Safety and Health Administration Safety Data.
101	XBRL Interactive Data File.

*	Pursuant to Item 601(b)(4)(iii) of Regulation S-K, this document(s) is not filed herewith. We hereby agree to furnish a copy to the SEC upon request.
**	Management contract or compensatory plan arrangement.
†	Incorporated herein by reference.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: March 15, 2024

By: /s/ DUANE HIGHLEY

Name: Duane Highley

Title: Chief Executive Officer

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DUANE HIGHLEY Duane Highley	Chief Executive Officer (principal executive officer)	March 15, 2024
/s/ TODD E. TELESZ Todd E. Telesz	Senior Vice President/Chief Financial Officer (principal financial officer)	March 15, 2024
/s/ DENNIS J. HRUBY Dennis J. Hruby	Vice President Controller (principal accounting officer)	March 15, 2024
/s/ TIMOTHY A. RABON Timothy A. Rabon	Chairman, President and Director	March 15, 2024
/s/ DONALD KEAIRNS Donald Keairns	Director	March 15, 2024
/s/ JULIE KILTY Julie Kilty	Director	March 15, 2024
/s/ STUART MORGAN Stuart Morgan	Director	March 15, 2024
/s/ THAINE MICHIE Thaine Michie	Director	March 15, 2024
/s/ SCOTT WOLFE Scott Wolfe	Director	March 15, 2024
/s/ CHARLES ABEL II Charles Abel II	Director	March 15, 2024
/s/ ARTHUR W. CONNELL Arthur W. Connell	Director	March 15, 2024
/s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	March 15, 2024
/s/ LEROY ANAYA Leroy Anaya	Director	March 15, 2024
/s/ ROBERT BACA Robert Baca	Director	March 15, 2024
Lucas Bear	Director	

/s/ ROBERT BLEDSOE Robert Bledsoe	Director	March 15, 2024
/s/ LAWRENCE BRASE Lawrence Brase	Director	March 15, 2024
Leo Brekel	Director	
/s/ WILLIAM BRIDGES William Bridges	Director	March 15, 2024
/s/ ROBERT BROCKMAN Robert Brockman	Director	March 15, 2024
Matt M. Brown	Director	
/s/ KEVIN COONEY Kevin Cooney	Director	March 15, 2024
/s/ ELIAS CORIZ Elias Coriz	Director	March 15, 2024
/s/ MARK DAILY Mark Daily	Director	March 15, 2024
/s/ JERRY FETTERMAN Jerry Fetterman	Director	March 15, 2024
/s/ JOEL GILBERT Joel Gilbert	Director	March 15, 2024
/s/ RICK GORDON Rick Gordon	Director	March 15, 2024
/s/ RONALD HILKEY Ronald Hilkey	Director	March 15, 2024
/s/ LARRY HOOZEE Larry Hoozee	Director	March 15, 2024
/s/ JOE HOSKINS Joe Hoskins	Director	March 15, 2024
/s/ CHRIS MARTINEZ Chris Martinez	Director	March 15, 2024
/s/ STANLEY PROPP Stanley Propp	Director	March 15, 2024
/s/ STEVE M. RENDON Steve M. Rendon	Director	March 15, 2024
/s/ PEGGY A. RUBLE Peggy A. Ruble	Director	March 15, 2024
/s/ ROGER L. SCHENK Roger L. Schenk	Director	March 15, 2024
Gary Shaw	Director	

/s/ DARRYL SULLIVAN Darryl Sullivan	Director	March 15, 2024
/s/ KEVIN THOMAS Kevin Thomas	Director	March 15, 2024
/s/ CLAY THOMPSON Clay Thompson	Director	March 15, 2024
/s/ WESLEY ULLRICH Wesley Ullrich	Director	March 15, 2024
/s/ WILLIAM WILSON William Wilson	Director	March 15, 2024
/s/ PHILLIP ZOCHOL Phillip Zochol	Director	March 15, 2024