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, 2021
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. The registrant has filed all Exchange Act reports for the preceding 12 months (or for such shorter period that the registrant was required to file such reports)).

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. ☐

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.

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GLOSSARY

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

Abbreviations or Acronyms	Definition
AQCC	Colorado Air Quality Control Commission
Basin	Basin Electric Power Cooperative
Board	Board of Directors
CAISO	California Independent System Operator
CDPHE	Colorado Department of Public Health and Environment
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
COVID-19	coronavirus disease 2019 that was declared a pandemic by the World Health Organization in March 2020
Craig Station	Craig Generating Station
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
DMEA	Delta-Montrose Electric Association
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)
EMS	Environmental Management System
EPA	Environmental Protection Agency
Elk Ridge	Elk Ridge Mining and Reclamation, LLC, a subsidiary of ours
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
Jurisdictional PDO	our Petition for Declaratory Order on Jurisdiction under Part II of Federal Power Act, filed with FERC on December 23, 2019, EL20-16-000
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 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.
MRO	Midwestern Reliability Organization

MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
Non-Utility Members	our non-utility members
NO_X	nitrogen oxide
NPPD	Nebraska Public Power District
NRECA	National Rural Electric Cooperative Association
OATT	Open Access Transmission Tariff
OSMRE	Office of Surface Mining Reclamation and Enforcement
PCB	polychlorinated biphenyls
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
Revolving Credit Agreement	Credit Agreement, dated as of April 25, 2018, between us and CFC, as administrative agent
RPS	Renewable Portfolio Standard
RS Plan	National Rural Electric Cooperative Association Retirement Security Plan
Salt River Project	Salt River Project Agricultural Improvement and Power District
S&P	Standard & Poor’s Global Ratings
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
Trapper Mining	Trapper Mining, Inc.
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
WAPA	Western Area Power Administration (a power marketing agency of the U.S. Department of Energy)
WECC	Western Electricity Coordinating Council
WFA	Western Fuels Association, Inc.
WFW	Western Fuels-Wyoming, Inc.
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, business strategy 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,” “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 615,000 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 cost 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.

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. FERC 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. Our rates were referred to administrative law judges to encourage settlement of material issues and to hold hearings if settlements were not reached. 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 addition, in March 2022, FERC approved a settlement agreement related to our transmission service rates. See "Note 15—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

In 2020, we also filed our "Make-Whole" contract termination payment methodology associated with a Utility Member terminating its wholesale electric service contract, our buy-down payment methodology for a Class A - utility full requirements member to become a Class B - utility partial requirements member, and our Board policy associated with partial requirements. FERC issued orders accepting these filings, subject to refund, but did not determine these filings were just and reasonable and ordered a FPA section 206 proceeding to determine the justness and reasonableness of such tariff filings. A consolidated settlement proceeding related to the two partial requirements tariff filings is on-going.

In September 2021, we filed our modified contract termination payment methodology associated with a Utility Member terminating its wholesale electric service contract. FERC accepted our modified contract termination payment methodology, 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 contract termination payment methodology. See " — MEMBERS – Relationship with Members."

Responsible Energy Plan

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 2024, 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.
- Expanding electric vehicle infrastructure and beneficial electrification.

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 long-term purchase contracts with respect to various generating facilities. As of December 31, 2021, our diverse generation portfolio provides us with maximum available power of 4,440 MWs and is summarized in the table below:

Generation Portfolio (as of December 31, 2021)	Capacity (MW)	Percentage (%)
Coal-fired base load facilities	1,551	35
Renewables-contracts, including WAPA	1,366	31
Gas/oil-fired facilities	903	20
Other contracts, including Basin	620	14

In 2021, we began purchasing energy pursuant to long-term power purchase agreements from a 200 MW wind-based generating facility and 104 MW wind-based generating facility that both achieved commercial operation in 2021. We have also executed six solar-based power purchase contracts totaling 735 MWs for facilities that are expected to achieve commercial operation in 2023 or 2024 . In January 2020, we announced the early retirements of Craig Station by 2030. In September 2021, we submitted to the COPUC our Revised Preferred Plan in connection with Phase I of our 2020 Electric Resource Plan that modeled the addition of 2,050 MWs of additional renewable resources and more than 200 MWs of electric storage during the resource acquisition period of 2021 to 2030. In January 2022, we reached a comprehensive proposed settlement agreement that sets emissions reduction targets for our wholesale electricity sales in Colorado that was filed with the COPUC for approval. 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 Unit 1 and the addition of new renewable generating resources, as of December 31, 2026, we anticipate our generation portfolio to be the following:

Anticipated Generation Portfolio (as of December 31, 2026)	**Capacity (MW)**	**Percentage (%)**
Coal-fired base load facilities	1,449	25
Renewables-contracts, including WAPA (1)	2,934	50
Gas/oil-fired facilities	903	15
Other contracts, including Basin	620	10

(1) Includes 850 MWs of resource needs through 2026, based upon our Revised Preferred Plan modeled in Phase I of our 2020 Electric Resource Plan.

In addition to our diverse generation portfolio, as permitted by our wholesale electric service contracts with our Utility Members, as of December 31, 2021, our Utility Members own or control through long-term purchase power contracts approximately 126 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 5,793 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 419 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.

Based upon a 2020 employee engagement survey of employees, 82 percent of employees are proud to work for our organization. Forbes named us as one of America's Best in-state employers in Colorado in the 2020 Forbes' America's Best in-state employers and recognized us for the positive ways in which we responded to the COVID-19 pandemic. This is reflected in our low employee turnover rate, which, in 2021, was below both our industry and the national average.

We recognize employee safety and health as a corporate value that is at the core of how we do business. We believe injuries and illness 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 our safety and health policies, programs and procedures and implement actions with the goal of continually improving our safety and health performance.

Including our subsidiaries, as of December 31, 2021, we employed 1,191 people, of which 215 were subject to collective bargaining agreements. As of December 31, 2021, none of these collective bargaining agreements will expire within one year. In 2021, our number of employees decreased by approximately 9 percent due to cost reduction efforts and other factors. Since 2016, our number of employees has decreased by approximately 25 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 2030 with the closure of additional facilities by 2030. 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, Inc.	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 purchases 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 the 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. At our August 2021 annual meeting of our Members, our Members approved amendments to our Bylaws to 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 "— MEMBERS — 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 "— MEMBERS — 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, 2021, 21 Utility Members have enrolled in this program with capacity totaling approximately 145 MWs of which 126 MWs are in operation. We estimate that in 2021 over a third of the energy our Utility Members used came from clean sources. See also "— MEMBERS – 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 loads are 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 2017 through 2021 and the amount of energy that we supplied them. Our Utility Members' 2021 peak demand increased 2.7 percent compared to 2020 and the annual amount of energy we sold to our Utility Members in 2021 decreased 1.3 percent compared to 2020.

Year	Utility Members' Peak Demand (MW) (1)	Amount of Energy Sold (MWh) (1)
2021	2,974	15,676,830
2020	2,896	15,884,777
2019	3,009	16,412,525
2018	2,974	16,384,415
2017	2,850	15,905,656

(1) Includes peak demand of and energy sales to DMEA 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 18.5 percent of our Utility Member revenue and 15.4 percent of our operating revenue in 2021. No other Utility Member exceeded 10 percent of our Utility Member revenue or our operating revenue in 2021. 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 the Board the community solar program, the partial requirements structure, including the buy-down payment methodology, and the methodology to calculate a contract termination payment.

The community solar program provides for a Utility Member to own or control, through a power purchase agreement, 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 is in addition to the 5 percent self-supply provision of the wholesale electric service contracts. Each Utility Member is eligible for community solar projects up to, in aggregate, the lesser of 4.6 million kWhs or 2 percent of such Utility Member's 2018 energy sales from us. The community solar program, if acted upon by all Utility Members, would be approximately 64 MWs of new community solar projects. As of December 31, 2021, one Utility Member has enrolled in this program.

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 program approved by FERC involving us and thirty of our Utility Members, we will purchase capacity and energy from qualifying facilities that interconnect to distribution systems of those Utility Members who are participating in the waiver program. 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 and the structure of a partial requirements contract. The partial requirements structure includes holding an open season for Utility Members to choose to enter into a partial requirements contract with us. The open season would permit Utility Members collectively to self-supply up to 300 MWs, approximately 10 percent of our Utility Members' peak demand. Under the new partial requirements membership construct, Utility Members can 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 community solar program. During our initial open season partial requirements nomination period that was completed in May 2021, three Utility Members nominated and were allocated an aggregate of 203 MWs of self-supply. No Utility Member has executed a partial requirement contract or become a Class B member. FERC approval will be required for each partial requirements contract.

In January 2022, our Board approved an extension of the initial open season to offer the remaining 97 MWs of the 300 MWs of self-supply to the Utility Members who did not participate in 2021. The extension of the initial open season will start in May 2022.

The Utility Members that choose the partial requirements option will make other Utility Members financially whole through a buy-down payment to us. Our Board approved buy-down payment methodology for a Class A member to become a Class B member was accepted by FERC in 2020, subject to refund. FERC referred it to FERC's hearing and settlement judge procedures and it was consolidated with FERC's hearing and settlement judge procedures for our contract termination payment methodology discussed below. United Power has filed a petition for review with the D.C. Circuit Court of Appeals related to FERC's acceptance of the buy-down payment methodology and such matter with the D.C. Circuit Court of Appeals is being held in abeyance pending resolution of the Jurisdictional PDO appeal. See "Note 15—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information regarding the Jurisdictional PDO appeal.

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. United Power has filed a petition for review with the D.C. Circuit Court of Appeals related to FERC's acceptance of the contract termination payment methodology and such matter with the D.C. Circuit Court of Appeals is being held in abeyance pending resolution of the Jurisdictional PDO appeal.

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 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. In September 2021, we filed with FERC both a response to the show cause order and 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 continues to be designed to protect the financial interests of our remaining Utility Members if a Utility Member elects to withdraw. Our September 2021 tariff filing includes requirements for a two-year notice and the payment of a contract termination payment. It also includes the contract termination payment amount for each of our Utility Members under the modified methodology assuming a January 1, 2024 withdrawal date. A number of our Utility Members and other parties have intervened in both the show cause order and our filing of a modified contract termination payment methodology. The directors on our Board representing a majority of our Utility Members voted in favor of our modified methodology and seven of such Utility Members filed comments with FERC in support of our filing. Four of our Utility Members filed a protest.

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. FERC did not consolidate our modified contract termination payment methodology with FERC's July 2021 show cause order nor with the on-going consolidated hearing and settlement procedures for our partial requirements buy-down payment methodology and our original contract termination payment methodology filed in 2020. In December 2021, the administrative law judge for the modified contract termination payment hearing adopted a procedural schedule with a hearing to occur in May 2022 and an initial decision to be issued by an administrative law judge by the end of July 2022. In December 2021, Basin filed a complaint claiming that the filing of our modified contract termination payment tariff constitutes a breach of our wholesale power contract with Basin for the Eastern Interconnection. See "Note 15—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information regarding Basin's complaint.

In December 2021, United Power provided us with notice that it intends to withdraw from membership in us with a January 1, 2024 withdrawal effective date. United Power asserts in its notice that United Power’s notice to withdrawal is non-binding and that it may revoke such notice at any time prior to January 1, 2024. United Power filed a request with FERC for FERC to adopt United Power’s interpretation of the withdrawal procedures in our September 2021 contract termination payment tariff filing that would permit United Power to revoke its notice of withdrawal at any time. We filed an answer with FERC to United Power’s claim that it may revoke its withdrawal notice, explaining such interpretation would be unjust and harmful to us and our membership. We further stated in our answer with FERC that United Power’s non-binding notice is defective under the contract termination payment tariff and therefore a nullity. Multiple Utility Members from each of our four states have also filed comments in support of our answer. Subsequent to United Power's non-binding notice, we also received in December 2021 non-binding membership withdrawal notices from Poudre Valley Rural Electric Association and Northwest Rural Public Power District. Except as provided above, no other Utility Member has requested to terminate its wholesale electric service contract with us or to withdraw from membership.

In May 2020, United Power filed a complaint for declaratory judgement and damages against us and our three Non-Utility Members 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, the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula are also void, that we have breached the wholesale electric service contract with United Power, and that we and our three Non-Utility Members conspired to deprive the COPUC of jurisdiction over the contract termination payment of our Colorado Utility Members. In July 2021, the court granted United Power's motion to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add a claim that our addition of the Non-Utility Members violated Colorado law. See "Note 15—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. Over the past two years, we and our Utility Members have made great strides implementing the plan, which has allowed us to set new goals beyond those identified in January 2020. The elements of our plan and progress highlights from 2021 are below:

- Reduce emissions – We retired Escalante Station in 2020 and have announced the retirement of Craig Station by 2030. By 2030 and relative to 2005 levels, in Colorado, 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 relative to 2005 levels.

  - *Progress in 2021*: Since 2019, we have decreased coal capacity by roughly 20 percent and filed our Revised Preferred Plan with the COPUC identifying a 80 percent reduction in CO_2 emissions associated with wholesale electricity sales in Colorado by 2030, relative to a 2005 baseline.

- Increase clean energy – By 2024, we expect to bring over 1,000 MWs of utility scale wind and solar projects online, doubling our system to over 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 2021*: We filed our Revised Preferred Plan with the COPUC identifying over 2,000 MWs of renewables and battery storage to increase our clean energy to roughly 4,000 MWs by 2030. In 2021, we began purchasing energy pursuant to long-term power purchase agreements from two wind-based generating facilities totaling 304 MWs. We estimate that in 2021 over a third of the energy our Utility Members used came from clean sources.

- 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 2021*: Since its inception in 2020, we have supported Utility Member installations of over 380 electric vehicle chargers through our electric vehicle infrastructure program. With support through our heat pump quality install program and rebates, we saw a 30 percent increase in heat pump installations throughout Utility Members' service territories.

- 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 2021*: Through an open season allowing Utility Members to request an allocation to self-supply a greater portion of their loads, we allocated 203 MWs of requested self-supply capacity to three Utility Members. We partnered with a Utility Member to support development of a remote community's microgrid to promote resilience through local generation. Throughout the year, we continued to work with our Utility Members to advance options that create flexibility for Utility Members that desire it without raising costs for the others.

- 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 2021*: We committed a donation of $5 million to support economic and community development following the 2020 retirement of Escalante Station. In addition, we worked with local and state leaders to begin exploring opportunities to retain employment and revenue in transitioning Colorado and New Mexico communities by co-locating hydrogen and other clean energy projects at power plant sites.

- Other elements – As we implement our Responsible Energy Plan, our goal is to maintain or reduce rates for Utility Members in all states. We are also promoting a western regional transmission organization to efficiently and cost-effectively integrate more renewables into the grid, and are striving for 100 percent clean energy in Colorado by 2040.
  - *Progress in 2021*: We lowered our Utility Members rates by two percent in March 2021 and will lower our Utility Members' rates by an additional two percent in March 2022. We entered two energy imbalance markets and 80 percent of our load is now in organized markets as we continue to evaluate participation in SPP's regional transmission organization in the Western Interconnection.

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. Approximately 4.6 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, all the power which we require to serve our Utility Members' load in the Eastern Interconnection. See "— POWER SUPPLY RESOURCES — Purchased Power."

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 loads 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 that our Utility Members serve by helping them create electric utilities.

RATE REGULATION

New Rate Developments

In April 2021, we filed a proposed settlement agreement for approval with FERC related to our Utility Member 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 resolves all issues set for hearing and settlement procedures related to our Utility Member rates. The settlement provides for us to implement a two-stage, graduated reduction in the charges making up our Class A rate schedule of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from current rates) thereafter until the date a new Class A wholesale rate schedule is approved by FERC and goes into effect. The settlement rates will remain in effect at least through May 31, 2023 and during such time period, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule. We have also agreed to file a new Class A rate schedule after May 31, 2023 and prior to September 1, 2023. During the moratorium, we have established a rate design committee to oversee the development of the new rate. The rate design committee consisting of a representative from each Utility Member. In August 2021, FERC approved this settlement agreement. See "Note 15—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

Three of the reserved issues contingent on United Power being a settling party are 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 will have prospective effect only, with the intent that any FERC rulings would be implemented in future rate filings. A hearing with an administrative law judge at FERC on the four reserved issued is scheduled to occur in March 2022 with an initial decision to be issued by an administrative law judge by the end of May 2022.

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 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, subject to FERC market-based rate authority. In December 2021, we filed with FERC our triennial market power update related our market-based rate authority applicable to the PSCO, PNM and WAPA balancing authority areas. FERC instituted a FPA section 206 proceeding related to our market-based rate authority in the WAPA balancing authority area and established a refund effective date of March 7, 2022 for market-based sales after such date.

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.” While our Board still has authority to determine our rates, those rates, including any change to the rate or rate structure, must be approved by FERC subject to outside comments. As part of the FERC approved settlement agreement, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule, at least through May 31, 2023.

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 two percent until the date a new Class A wholesale rate schedule is approved by FERC and goes into effect.

A rate design committee consisting of a representative from each Utility Member is working on the development of a new rate to our Utility Members.

Rate Policy

Under the 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 requires us to maintain an ECR of at least 18 percent at the end of each fiscal year. Our Board has adopted and periodically reviews and revises a Board Policy for Financial Goals and Capital Credits, which currently targets rates payable by our Utility Members to produce financial results above the requirements of our Master Indenture. 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. The 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 2017 through 2021. 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 2017 through 2021.

Year	Average Utility Member Revenue (Cents/kWh)
2021	7.408
2020	7.531
2019	7.547
2018	7.543
2017	7.544

Other FERC Regulation

In addition to FERC's jurisdiction over our wholesale rates to our Utility Members 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 2021, 52.1 percent of our energy available for sale was provided by our generation and 47.9 percent by purchased power. We expect the amount of energy we purchase to increase in the future with the closures of our coal-fired base load facilities and the increasing amount of renewable power purchase contracts. We estimate that in 2021 over a third of the energy our Utility Members used came from clean sources. We estimate that by 2024, 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, have undivided percentage interests in, or have tolling arrangements with respect to 1,551 MWs from coal-fired base load facilities and 903 MWs from gas/oil-fired facilities. See "PROPERTIES" for a description of our various generating facilities.

On September 1, 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. On January 9, 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 and we intended to retire Craig Station Unit 3 by December 31, 2029. The early retirement of Craig Station is expected to impact approximately 175 employees.

In August 2021, we completed merging the entities that owned J.M. Shafer Generating Station, including Thermo Cogeneration Partnership, L.P., into Tri-State.

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 1,521 MWs, including 674 MWs of wind-based power purchase contracts and 820 MWs of solar-based power purchase contracts, of which 785 MWs are in operation. The largest of these renewable power purchase contracts are summarized in the table below. Certain of these renewable power purchase contracts for renewable facilities that have not achieved commercial operation include conditions precedent that if not satisfied may result in termination of such contract. 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	Colorado	Axial Basin Solar, LLC	Solar	145	2023	(1)	2038	(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	
Coyote Gulch Solar	Colorado	Coyote Gulch Solar, LLC	Solar	140	2024	(1)	2039	(2)
Crossing Trails Wind	Colorado	Crossing Trails Wind Power Project, LLC	Wind	104	2021		2036	
Dolores Canyon Solar	Colorado	Dolores Canyon, LLC	Solar	110	2023	(1)	2038	(2)
Escalante Solar	New Mexico	Escalante Solar, LLC	Solar	200	2023	(1)	2040	(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	2023	(1)	2038	(2)
Spanish Peaks Solar II	Colorado	Spanish Peaks II Solar, LLC	Solar	40	2023	(1)	2038	(2)
Twin Buttes II Wind	Colorado	Twin Buttes Wind II, LLC	Wind	75	2017		2042	

(1) Anticipated year of commercial operation.
(2) Anticipated year of contract expiration based upon anticipated year of commercial operation.

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 contracts, two contracts relating to WAPA's Loveland Area Projects (one which terminates September 30, 2024 and one which commences delivery on October 1, 2024 and terminates September 30, 2054) and three contracts relating to WAPA's Salt Lake City Area Integrated Projects (two which terminate September 30, 2024 and one which commences delivery on October 1, 2024 and terminates September 30, 2057). The Loveland Area Projects generally consist of generation and transmission facilities located in the Missouri River Basin. The Salt Lake City Area Integrated Projects generally consist of generation and transmission facilities located in the Colorado River Basin. The following table shows the 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

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 United States 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. Our December 2021 capacity allocations were reduced by approximately 55 percent and the energy allocations were reduced by approximately 38 percent. Our first quarter of 2022 capacity allocations were reduced by approximately 44 percent and our energy allocations were reduced by approximately 38 percent. We expect similar reductions for the remainder of 2022.

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. The Utility Members' peak load in the Eastern Interconnection in 2021 was approximately 352 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.

Other. In 2016, we entered into a five–year reciprocal contract that contained renewal provisions with PNM to sell PNM 100 MWs of power, contingent on the operation of Springerville Unit 3, and purchase from PNM 100 MWs of power, contingent on the operation of PNM's San Juan Generating Station Unit 4. In 2021, PNM provided notice to terminate this contract at the end of May 2022. This contract with PNM reduces our amount of needed operating reserves and reduces the amount of power we would need to purchase in the event of a forced outage of Springerville Unit 3. The net of the sales revenue and purchased power costs under this contract is included in purchased power expense on our consolidated statements of operations.

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 various long-term power sales contracts with other entities totaling approximately 200 MWs, which are discussed below. We have a contract to sell Salt River Project 100 MWs of power, contingent on the operation of Springerville Unit 3, which expires in August 2036. We also have a five-year reciprocal contract to sell PNM 100 MWs of power, contingent on the operation of Springerville Unit 3 that terminates in May 2022. See "— POWER SUPPLY RESOURCES – Purchased Power."

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

On February 1, 2021, SPP launched the Western Energy Imbalance Service market with eight utilities participating, including us. The Western Energy Imbalance Service market generally covers our loads and resources in western and northeastern 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, and is expected to enhance both the reliability and affordability of electricity delivered from utilities to their customers. It will also help facilitate the integration of additional renewable resources within the region. In January 2022, PSCO announced that it plans to join the Western Energy

Imbalance Service market commencing in April 2023. This will cover all our loads and resources within the PSCO balancing authority, which is approximately 20 percent of our load.

In April 2021, PNM joined as an EIM entity in the CAISO Western Energy Imbalance Market. This affects our loads and resources within the PNM balancing authority, which is all our loads and resources in New Mexico. We have registered with CAISO as a participating scheduling coordinator, and registered our New Mexico resources and Springerville Unit 3 generation as participating resources with the CAISO, in order for our generation to participate in this imbalance market. We have had Utility Member load in the CAISO Western Energy Imbalance Market since it began in 2015 with our small amount of load in the PacifiCorp balancing authority.

Our load and transmission facilities in the Eastern Interconnection, largely in Nebraska, have been in the SPP regional transmission organization since 2016. Upon PSCO joining the Western Energy Imbalance Service market, we will have all our load in organized markets.

We continue to explore options to participate in a regional transmission organization in the Western Interconnection. We, together with Basin, WAPA, Municipal Energy Agency of Nebraska, Deseret Power Electric Cooperative, and Colorado Springs Utilities, continue discussions for participation in SPP's regional transmission organization in the Western Interconnection. In July 2021, SPP's board of directors approved the terms and condition for an expansion of SPP's regional transmission organization in the Western Interconnection. We believe a Western Interconnection regional transmission organization is necessary to achieve the full benefits of organized markets and to meet future state carbon goals.

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 renewable portfolio additions, we monitor market conditions, tax credit expiration schedules, impacts of current renewable 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 and RPS and other similar state laws and goals regarding reductions in CO_2 emissions. Consistent with this strategy, our most recent request for proposal issued in June 2019 and subsequent award of power purchase contracts for 200 MWs of wind and 635 MWs of solar allowed us to add cost effective resources to our power supply portfolio.

In 2019, Colorado legislation was signed that requires us to file and obtain COPUC approval for our electric resource plan and directs that such plan consider the cost of CO_2 emissions associated with our generating facilities. 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, which contained our Preferred Plan. In June 2021, the COPUC issued an interim decision deeming our 2020 Electric Resource Plan application complete and referring the case to an administrative law judge. In September 2021, we submitted the results of modeling additional Electric Resource Plan scenarios including our Revised Preferred Plan, alongside supplemental direct testimony. Our Revised Preferred Plan includes 2,050 MWs of additional renewable generation and more than 200 MWs of energy storage occurring during the resource acquisition period of 2021 to 2030. In January 2022, we reached an unopposed comprehensive proposed settlement agreement with the majority of intervening parties to the proceeding and filed it with the COPUC for approval. The proposed 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 implements new energy efficiency and demand response targets and limits procurements from Phase II of the Electric Resource Plan to 2025 and 2026. The COPUC is expected to consider and act on the filing in 2022. Our resource needs through 2026, based upon our Revised Preferred Plan modeled in Phase I, reflect another 300 MWs of wind resources and 550 MWs of solar resources. Procurements in Phase II will be determined through additional modeling and in accordance with the unopposed comprehensive settlement agreement reached in Phase I.

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	Annual Tonnage—Our Share (approximate)
Craig Station Units 1 and 2	Colowyo Mine	2029	800,000
Craig Station Unit 3	Colowyo Mine	2029	1,300,000
Laramie River Generating Station	Various, including Dry Fork Mine	2041	1,900,000
Springerville Unit 3	North Antelope Rochelle Mine	2024	900,000 to 1,400,000

Colowyo Mine. As current mining operations in the South Taylor pit are being completed and land is being reclaimed, Colowyo Coal, a subsidiary of ours, is continuing to develop and actively mine the Collom pit at the Colowyo Mine to access coal reserves for future production. In January 2017, Colowyo Coal received final approval of the mining plan from OSMRE. In November 2019, CDPHE issued an air permit revision for the construction and operation of the Collom pit. Coal production from the Collom pit began in July 2019. See "— ENVIRONMENTAL REGULATIONS – Other Environmental Matters."

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 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 Colowyo Mine and 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 the natural gas we purchase is for facilities used primarily to fill peak demands. 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 United States 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 5,793 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 419 substations and switchyards. See “PROPERTIES” for a description of our transmission facilities.

Our system is interconnected with those of other utilities, including WAPA, NPPD, 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. We filed our electric tariff, including the OATT, in December 2019. In March 2020, FERC accepted our OATT, but did not determine that our transmission service rates were just and reasonable and ordered a FPA section 206 proceeding to determine the justness and reasonableness of our rates. The transmission tariff rates were referred to an administrative law judge to encourage settlement of material issues and to hold a hearing if settlement is not reached. In October 2021, we filed a proposed settlement agreement for approval with FERC related to our transmission service rates. In March 2022, FERC approved the settlement agreement. See "Note 15—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

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, which constitute about 3.6 percent of our total transmission facilities. 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 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, Colorado, Wyoming, 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 Northwest 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 is still evaluating the preliminary findings of the 2021 audit, however, we do not expect there to be any significant enforcement actions.

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 $6.6 million through 2026 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 stations 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 each year by our Board. The policy commits us to comply with all environmental laws and regulations. The policy also calls for the enforcement 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 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. The Colorado legislation will have a material impact on our operations and our future generation portfolio; however, until the final rules are enacted that implement the legislation, it is not yet possible to estimate the impacts on our operations or future generation portfolio. The AQCC has not yet developed or adopted rules to implement the legislation. As part of the proposed settlement agreement related to our 2020 Electric Resource Plan that was filed with the COPUC for approval in January 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. These amounts will be calculated based on our 2005 emissions baseline for wholesale sales in Colorado. See "— POWER SUPPLY RESOURCES – Resource Planning" regarding our 2020 Electric Resource Plan.

In 2019, New Mexico legislation was signed that amends the existing RPS that requires our New Mexico Utility Members to obtain 10 percent of their energy requirements from renewable sources in 2020 and thereafter. The legislation adds 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 RPS law requires our Colorado Utility Members to obtain 10 percent 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 RPS requirement towards compliance with our separate RPS requirement.

We currently provide sufficient energy from renewable sources to meet our Utility Members' current obligations under the RPS requirements in New Mexico and Colorado and expect to be able to continue meeting our Utility Members' RPS obligations in 2022 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 RPS that requires 20 percent of the energy we provide to our Colorado Utility Members at wholesale to come from renewable sources in 2022.

The impacts of the 2019 Colorado and New Mexico legislation and our compliance with the settlement agreement related to our 2020 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, 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, baghouses 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. Between 2010 and 2020, we accomplished a 49 percent decrease in annual NO_X emissions, a 32 percent decrease in annual SO_2 emissions, and a 17 percent decrease in annual CO_2 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 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 five 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. An emission allowance, which gives the holder the authority to emit one ton of SO_2 during a calendar year, is transferable and can be bought, sold or banked in the years following its issuance. Allowances are issued by the EPA. The aggregate nationwide emissions of SO_2 from all affected units are now capped at 8.95 million tons per year. We receive and hold sufficient SO_2 allowances for compliance with the acid rain program and send excess allowances back to our general account. Allowances have been issued by EPA through compliance year 2046 and we have additional general account allowances that would provide for additional years based on our current usage rate.

Greenhouse Gas Regulation. In October 2015, the EPA published in the Federal Register a final rule regarding emission limits and emission guidelines of CO_2 for existing generating facilities in a comprehensive rule referred to as the "Clean Power Plan." The Clean Power Plan established guidelines for states to develop plans to limit emissions of CO_2 from existing units. The goal of the rule was a reduction in CO_2 emissions from 2005 levels of 32 percent nationwide by 2030 and specifies interim emission rates phasing in between 2022 and 2029.

In February 2016, the United States Supreme Court granted numerous applications to stay the Clean Power Plan pending judicial review. The appeal of the Clean Power Plan was held in abeyance until the EPA published a proposal to repeal the Clean Power Plan. In July 2019, the EPA finalized the repeal of the Clean Power Plan and replaced it with the Affordable Clean Energy (also known as ACE) rule. The Affordable Clean Energy rule established guidelines for states to follow in developing limitations (i.e., standards of performance) for CO_2 emissions from existing units, based on an EPA determination that the best system of emission reduction is heat rate improvement. 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. The Biden administration is expected to begin another, new rulemaking and has stated its intent to issue a new proposed rule in 2022.

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 in 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.

New Source Review. Section 114(a) Information Requests related to New Source Review Program Requirements. Over the past two decades, the United States 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 December 2019, the EPA reclassified the DM/NFR ozone nonattainment area from “moderate” to “serious” nonattainment for the 2008 ozone NAAQS of 75 ppb. The EPA and the State of Colorado have stated that they plan to again redesignate the DM/NFR ozone nonattainment area from "serious" to "severe" nonattainment in 2022 for failure to attain the 2008 NAAQS. Currently, it is not anticipated that additional areas will be designated as nonattainment for the more stringent 2015 ozone standard. It is expected that the DM/NFR ozone nonattainment area will be required to submit a plan to comply with the 2015 ozone NAAQS by 2023. The EPA has stated that it will reconsider its previous decision to set the 2015 standard at 70 ppb and may lower the numerical value of the standard. Implementation of an ozone standard of 70 ppb or less will require the evaluation of additional emission controls for many major sources in the DM/NFR nonattainment area. Additional emission controls may or may not be required at the J.M. Shafer Generating Station and the Knutson Generating Station.

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 United States. Under the amended rule, certain types of older sources may be required to install best available retrofit technology and states were to establish Reasonable Progress Goals in SIPs to meet a 2064 goal of natural visibility conditions. The amended Regional Haze Rule could require additional controls for particulate matter, SO_2 and NO_X emissions from utility sources.

Due to a variety of factors, states’ regional haze plans for the second 10-year period are still in development or processes of approval before being sent to the EPA. 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. Arizona and Wyoming are still in processes of evaluating emission sources and developing regional haze plans. In Arizona, Springerville Unit 3 commenced operation in 2006 and has state-of-the-art emission controls. In Wyoming, Laramie River Station installed selective catalytic reduction on Unit 1 and selective non-catalytic reduction on Units 2 and 3 during the previous regional haze period. It is possible that additional emission controls and/or compliance emission limits could be proposed as part of the next regional haze plans in these states.

The Regional Haze Rule requires that states revise their SIPs every ten years. Therefore, like many environmental requirements, the Regional Haze Rule could require further reductions if needed to meet Reasonable Progress goals in the future.

Water Quality

The Clean Water Act. The Clean Water Act regulates the discharge of process wastewater and certain storm water under the National Pollutant Discharge Elimination System permit program. At the present time, we have the required permits under the program for all of our generating facilities. The water quality regulations require us to comply with each state’s water quality standards, including sampling and monitoring of the waters around affected plants.

The Navigable Waters Protection Rule, promulgated in April 2020, was overturned by several court decisions in 2021 and is currently not in effect nationwide. The EPA and Corps are currently using the pre-2015 definitions of WOTUS. The agencies plan a two-part rulemaking to again attempt to define WOTUS. The first proposed rule was published in December 2021 and would largely revert to the definitions in effect between 1986 and 2015. The agencies’ second rulemaking will start with a series of regional roundtables where selected participants will provide input and ideas to aid the agencies’ development of the second rule. The agencies requested submissions from the public for roundtable participant candidates and selection is pending. The roundtables may occur in early 2022, but dates are currently unknown. Many of our construction activities in WOTUS are authorized by streamlined general permits that are not anticipated to be substantially affected by changing 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 United States. The outcome of the 21st Conference of the Parties held by the United Nations in Paris during December 2015 is a broad international agreement based on non-binding commitments with no enforcement provisions known as the Paris Agreement; therefore, the agreement will not directly dictate any particular emission reduction obligations for United States businesses. Commitments are subject to review every five years under the agreement. In January 2021, President Biden, on behalf of the United States, accepted the 2015 Paris Climate Agreement.

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.

Collom Air Permit. In November 2019, the Collom air permit revision for the Collom pit at the Colowyo Mine was issued by CDPHE. In December 2019, the Center for Biological Diversity and Sierra Club filed a new case challenging the CDPHE's issuance of the Collom air permit revision. In October 2020, the judge issued an order affirming the CDPHE's issuance of the minor source construction air permit to Collom. The Center for Biological Diversity and Sierra Club appealed the decision to the Colorado Court of Appeals. The Center for Biological Diversity/Sierra Club, CDPHE and we have all filed respective briefs with the court. Oral arguments are scheduled for March 17, 2022.

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.

Endangered Species Act. Compliance with the Endangered Species Act 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 Endangered Species Act applies to us indirectly because it obligates federal agencies that are taking some form of permit, right-of-way, funding or other action. We regularly need federal permits and approvals from various agencies as part of our operations and plans. Environmental groups frequently petition the USFWS to protect additional species and challenge regulatory and species listing decisions. The outcomes of Endangered Species Act litigation results in a dynamic regulatory environment. The USFWS manages future species listings via a 5-year National Listing Workplan, which was updated in January 2021. We monitor the workplan for upcoming species listings that might affect our operations and plans. In particular, we are paying attention to several species with workplan timing estimates in the next few years such as: three bat species, the plains spotted skunk, the western bumble bee and the monarch butterfly. It is difficult to predict if and how these potential future species listings might affect our operations because USFWS may decline to list certain species or may list species with regulatory provisions or guidance that reduces or eliminates restrictions on our activities.

We are proactively engaging in the ongoing and pending listing decision for the lesser prairie-chicken, which occurs in southeastern Colorado and New Mexico and overlaps with some of our project plans and land holdings. In June 2021, the USFWS proposed listing the lesser prairie-chicken as threatened and endangered in the northern and southern portions of its range respectively. As proposed, our existing infrastructure and planned project are in the northern portion where the less restrictive threatened status would apply. The workplan does not specify a final lesser prairie-chicken listing rule date, but we anticipate this for the summer of 2022. The USFWS has also approved a private entity's habitat mitigation bank, and an incidental take permit for the lesser prairie-chicken. Electric utilities can choose to participate in these programs and we are evaluating their ability to cost-effectively meet our needs.

The USFWS finalized multiple Endangered Species Act regulatory changes in the past several years that could have improved Endangered Species Act implementation. Regulatory changes most recently proposed in 2021 would reverse previous changes related to critical habitat designations and a general definition of habitat.

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 withdrawal disputes, including, but not limited to, testimony submitted in connection therewith, may materially impact our financial condition, results of operations, long-term system resource planning, and our long-term debt.

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. FERC set the modified methodology for hearing and instituted a concurrent FPA section 206 proceeding to determine the justness and reasonableness of our modified methodology. See “BUSINESS — MEMBERS – Relationship with Members.” FERC has determined it has exclusive jurisdiction over the termination of our wholesale electric service contracts with our Utility Members. United Power has filed various legal actions challenging our addition of our Non-Utility Members, FERC’s jurisdiction over us, and our contract termination payment methodology. See "Note 15— Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

In December 2021, United Power provided us with a non-binding notice that it intends to withdraw from membership in us with a January 1, 2024 withdrawal effective date. Subsequent to United Power's non-binding notice, we also received non-binding withdrawal notices from Poudre Valley Rural Electric Association and Northwest Rural Public Power District. We filed certain answers to these non-binding notices with FERC explaining that non-binding notices are defective under the contract termination payment tariff and therefore a nullity. See "BUSINESS — MEMBERS – Relationship with Members."

If United Power is successful in its challenges resulting in the COPUC or any other state commission or state regulatory body having jurisdiction over the terms and conditions for a Utility Member’s withdrawal from us, and if the COPUC or any other state jurisdiction or state regulatory body determines the terms and conditions for a Utility Member to withdraw that are less than the monetary value as our Board may proscribe, it may materially impact us. If FERC determines the terms and conditions for a Utility Member to withdraw that are less than the monetary value as calculated pursuant to our modified contract termination payment methodology, it may materially impact us. If our modified 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. In addition, if FERC agrees with United Power's assertion that a Utility Member may provide a non-binding notice of withdraw, 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 any testimony we submit in connection with withdrawal disputes, it may materially impact us. FERC approval of a contract termination payment methodology that requires low payments by withdrawing Utility Members could cause a Material Adverse Effect (as defined in our 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, a materially adverse effect on our financial condition and results of operations, a material hindrance in our long-term system resource planning, and we may be required to offer a prepayment of certain of our long-term debt, without paying a contract termination payment. In addition, an offer of prepayment or prepayment of certain of our long-term debt could be viewed by lenders as triggering an event of default under the cross-default provision of certain of our loan agreements, including our 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 the Master Indenture.

Our ability to raise our Utility Members’ wholesale rates is limited and we are subject to rate regulation.

Wholesale rate changes for our Utility Members must be approved by a majority of our Board, which is comprised of one representative from each of our Utility Members and is also subject to FERC approval or acceptance. FERC has accepted our existing Class A wholesale rate structure (A-40) to our Utility Members as a “stated rate.” As part of the FERC approved settlement agreement related to our Utility Member stated rate, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule. We have also agreed to file a new Class A rate schedule after May 31, 2023 and prior to September 1, 2023. We have established a rate design committee to oversee the development of the new rate. See "BUSINESS — RATE REGULATION."

Upon our next rate change, we will be required to propose the new rates to our Utility Members in a tariff filing at FERC with a rate case, which is likely to be contested.

The moratorium on any rate increases to our Class A rate schedule until after May 31, 2023 may require us to utilize some or all of our deferred revenues and incomes in order to achieve a DSR equal to the DSR goal contained in our Board Policy for Financial Goals and Capital Credits. In addition, if unexpected events occur and we do not have sufficient deferred revenues and incomes, it could have an adverse effect on our results of operations and financial condition and we might not meet the DSR requirement in our Master Indenture.

Challenges to the rates approved by our Board and filed with FERC for approval, including our next rate change developed as part of the settlement agreement that will be filed in 2023, could make it difficult for us to adjust the wholesale rates to our Utility Members as completely or rapidly as necessary in response to changes in our operations or market conditions, which could have an adverse effect on our results of operations and financial condition.

Furthermore, our ability to create a regulatory asset or the utilization of regulatory liabilities, including associated with the early retirements of our generating facilities to implement the Responsible Energy Plan, 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.

FERC may also review our rates upon its own initiative or upon complaint and order a reduction of any rates determined to be unjust, unreasonable, or otherwise unlawful and order a refund for amounts collected during such proceedings in excess of the just, reasonable, and lawful rates.

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. If we were to no longer have market-based rate authority or 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.

If United Power is successful in its challenges regarding our addition of our Non-Utility Members or FERC’s jurisdiction over us, we may be subject to further and increased pressure by state regulatory agencies, including the COPUC, to regulate our rates and charges to our Utility Members, including the contract termination payment methodology associated with Utility Member withdrawals and any buy-down payment methodology associated with partial requirements contracts.

The competitiveness of our wholesale rates to our Utility Members could result in continued and additional Utility Member unrest.

Our mission is to provide our Utility Members with a reliable, affordable and responsible supply of electricity in accordance with cooperative principles. While the price for wholesale electricity has increased substantially in the past year, our wholesale rates remain higher than other wholesale suppliers, resulting in continued Utility Member unrest and pressure from Utility Members on us to lower our wholesale rates.

In 2021, our Board approved, and FERC accepted, as part of the settlement agreement related to our Utility Member stated rate, a two-stage, graduated reduction in the charges making up our Class A rate schedule of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from current rates) thereafter until the date a new Class A wholesale rate schedule is approved by FERC and goes into effect. See “BUSINESS — RATE REGULATION.” Although we believe that these reductions will help address our Utility Member concerns regarding the competitiveness of our wholesale rates, there can be no guarantee that such rate reduction will address their concerns or that we will be able to continue such reduction in wholesale rates in the future or reduce our rates further. If our Utility Members do not believe that we have adequately addressed their concerns through our rate reduction or we are not able to continue such reductions in the future or further reduce rates, 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 or 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 our Utility Members serve by claiming to be able to offer lower priced and cleaner wholesale electric power. It also includes assisting the communities 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. In June 2015, FERC clarified that the 5 percent limitation in our wholesale electric service contracts with our Utility Members related to distributed or renewable generation owned or controlled by our Members did not supersede PURPA and the requirement of our Members to purchase power from qualifying facilities. 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.

A number of other significant factors have affected electric utility operations, including the availability and cost of fuel for electric energy generation; the use of alternative fuel sources for space and water heating and household appliances; fluctuating rates of load growth; compliance with environmental and other governmental regulations; licensing and other factors affecting the construction, operation and cost of new and existing facilities; and the effects of conservation, energy management, and other governmental regulations on electric energy use. All of these factors present an increasing challenge to companies in the electric utility industry, including our Utility Members and us, to reduce costs, increase efficiency and innovation, and improve resource management.

We may face competition as a result of the factors described above, including competition from qualifying facilities, other utilities, competing energy suppliers, fuel sources or as a result of technological innovations. Technological innovations may include methods or products that allow consumers to by-pass 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 withdrawal from membership in us, annexations by municipalities, helping municipalities 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 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 2020 data in most cases, and not independently verified by us, industrial and large commercial customers account for approximately 40 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 16 percent of the aggregate retail electric energy sales of our Utility Members, based on the same data from our Utility Members. Outages at facilities of certain of these large customers due to COVID-19 has reduced demand from and energy sales to our Utility Members and such demand and energy sales have not returned. Additional or continued outages at facilities of these customers could continue to reduce demand from and energy sales to our Utility Members. A downturn in the economy, lower natural gas prices, demand for increased renewable energy, additional federal or local environmental restrictions imposed on their operations, or other changes in business conditions could affect this sector of the energy industry and sales could decrease in the future should these industrial and large commercial customers decide to decrease their operations, shut down operations, or elect to self-generate.

Our Responsible Energy Plan may not achieve Utility Member, environmentalist, lender, local community, or other stakeholder acceptance which may impact our financial condition or future plans.

In January 2020, we released our Responsible Energy Plan. See "BUSINESS — MEMBERS – Responsible Energy Plan." Although we believe that our Responsible Energy Plan addresses Utility Member concerns regarding access to more renewable energy, addresses environmentalist concerns regarding clean energy, addresses lender concerns regarding increasing our renewable energy portfolio, addresses laws and regulations applicable to us or our Utility Members, and provides assistance to transitioning communities, there can be no guarantee that these stakeholders or other stakeholders will continue to be receptive of our Responsible Energy Plan. In addition, certain aspects of our Responsible Energy Plan, including the scheduled early retirements of coal-fired generating facilities and increased Utility Member flexibility, require regulatory approvals. If our Utility Members, environmentalists, legislatures, regulatory agencies, lenders, local communities, or other stakeholders are no longer receptive of our Responsible Energy Plan or our next Electric Resource Plan filed with the COPUC, or believe that we have not adequately addressed their concerns, we may experience additional Utility Member unrest and desires to withdraw, unfavorable media coverage or other negative consequences which may impact our financial condition or future plans.

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 2021, 86.4 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 default could triggering 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 transitioning to a cleaner generation portfolio. We are also facing increasing regulatory oversight and prospects 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, unfavorable media coverage or other negative consequences which may impact our financial condition or 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 liable 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, may increase our costs of operation and further affect the utilization of current generation facilities.

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. 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. The Biden administration has already issued a series of executive orders focused on clean energy and climate change, including rejoining the Paris Agreement. The Biden administration has stated it has a goal to achieve a carbon pollution-free power sector by 2035 and to put the United States 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 requirements imposed on us or our Utility Members, could result in significant additional costs, including capital expenditures. Implementation of regulations on existing legislation 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 2021, our existing generating facilities generated approximately 52.1 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 on existing legislation and future legislation or regulation 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 certain environmental regulations addressing limitations on greenhouse gas emissions and RPS.

Litigation relating to environmental issues, including claims of property damage or personal injury caused by greenhouse gas emissions, has increased generally throughout the United States. 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 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 risk. Physical risks include changes in weather conditions and extreme weather events. Our Utility Members' customers' energy needs 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 prices charged by our suppliers which 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. To the extent insurance markets view climate change and emissions of greenhouse gas emissions as insurance risk or elect not to insure generation facilities that have greenhouse gas emissions, this 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 our Utility Members' customers' usage and demand for energy or could result in us incurring obligations to third parties related to such events. These factors could negatively impact our results of operations, financial condition or cash flows.

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 United States, especially in the southwest United States, 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 or cash flows.

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, 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.

Changes in power generation energy sources could reduce demand for our electric services.

Significant changes have taken place and are continuing in the electric industry related to self-generation and power generation energy sources such as fuel cells, batteries, micro turbines, wind turbines and solar cells. Adoption of these generation energy sources are continuing to increase because of technological advancements, government subsidies, law and regulations, and a perception that generating electricity through these energy sources is more environmentally friendly than generating electricity with fossil fuels. Increased adoption of these energy sources could reduce electricity demand and the pool of customers from whom fixed costs are recovered or could cause the temporary or permanent shutdown of individual generating units, including the shutting down of additional coal-fired generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled, resulting in higher rates to our Utility Members. Increased self-generation and the related use of net energy metering, which allows our Utility Members' self-generating customers to receive bill credits for surplus power, could reduce demand for electricity from our Utility Members. If these technologies were to develop sufficient economies of scale and we were unable to adjust our prices to reflect reduced electricity demand and increased self-generation and net energy metering, the competitiveness of our facilities, our financial condition and results of operations could be adversely affected.

The retirements of our existing generating facilities may impact reliability for our Utility Members.

The early retirement of our former and existing generating facilities, including Craig Station, may impact our ability to deliver reliable electric power to our Utility Members. 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 may require us to construct additional dispatchable generating facilities. As we pursue a 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 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 to loads 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 plan to increase our renewable portfolio, and as other utilities are also increasing their renewable portfolios the addition of renewable resources is expected to increase 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 additional transmission lines.

In most cases, construction of transmission lines presents numerous challenges. Environmental and state and local permitting and sitting processes may result in significant inefficiencies and delays in construction. 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 that meet the time and cost expectations of the clean energy transition, and we may need to rely on purchases of market priced electric power, which could put increased pressure on electric rates.

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, rail transportation issues have caused transportation companies to be unable to perform their contractual obligations to deliver coal on a timely basis and 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 continue to occur in the future due to any of the disruptions described above. In addition, if challenges to the permit for the Collom pit at the Colowyo Mine affect the operation of the Collom pit, it may affect our inventory of fuel supplies. Natural gas and oil supplies can also be subject to disruption due to 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.

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, the following:

- 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;
- ability to maintain and retain a knowledgeable workforce;
- work slowdown or stoppages due to communicable diseases or other factors;
- availability and cost of 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 as 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.

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 United States. Generally, low gas prices correlate to low wholesale electricity prices and thereby could 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 additional coal-fired generating facilities or 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.

Mandatory COVID-19 vaccination of employees could have a material adverse impact on our business and results of operations.

A new or amended rule that requires all our employees be vaccinated or undergo weekly COVID-19 testing may result in employee attrition, which could be material as a substantial number of our employees are believed to be unvaccinated. If we were to lose employees, it could have an adverse effect on our ability to operate and maintain our facilities and lead to service outages, business interruptions, and our ability to deliver power to our Utility Members, which could have an adverse effect on future revenues and costs, which could be material.

The widespread outbreak of a communicable disease, including the continued spread of COVID-19, or any other public health crisis, could have a material adverse effect on our business.

The widespread outbreak of a communicable disease, or any other public health crisis, including the on-going COVID-19 pandemic, could have a material adverse effect on our results of operations, financial condition and cash flow. Measures to control the spread of COVID-19 reduced demand for electricity from our Utility Members' customers and the demand from certain commercial customers, particularly oil and gas, have not returned. The COVID-19 pandemic has also disrupted the global supply chain and adversely impacted our suppliers. The extent to which the COVID-19 pandemic may continue to impact our results of operations, including the long-term nature of the impact, depends on numerous evolving factors, which are highly uncertain and difficult to predict.

We are exposed to cost uncertainty in connection with our construction projects at existing generating facilities, new and existing transmission facilities, and in connection with decommissioning of certain existing generating 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. We also upgrade and build new transmission facilities to maintain reliability, for load growth, or the accommodation of new generation. In the years 2022 through 2026, we estimate that we may invest approximately $619 million in new transmission facilities and upgrades to our existing transmission facilities.

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;
- sitting, permits, approvals and other regulatory matters;
- unforeseen engineering problems;
- work slowdown or stoppages due to communicable diseases or other factors;
- environmental and geological conditions;
- environmental litigation;
- delays or increased costs to interconnect our facilities with transmission grids;
- increased costs due to inflation;

- unanticipated increases in cost of materials and labor and supply chain interruptions; and
- performance by engineering, construction or procurement contractors.

The early retirement of and decommissioning of certain of our existing generating facilities, including Craig Station, is subject to substantial risks. In addition, the early retirement of and decommissioning of additional existing generating facilities 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. Closure of any of such generating facilities may force us to incur higher costs for replacement capacity and energy and will make us more reliant upon our remaining generating facilities and 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 to achieve our goal of lowering Utility Member rates, during this transition to a cleaner generation portfolio, 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.

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

We have ownership or capacity interests in approximately 5,793 miles of high voltage 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, which liability could be substantial and in excess of our liability insurance. Any such liability could materially affect us and our financial condition, future results of operations, and cash flow.

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 2021, purchased power provided 47.9 percent of our energy requirements. We expect the amount of energy we purchase to increase in the future with the closures of our coal-fired base load facilities and the increasing amount of 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 also exposed to the risk that counterparties to our renewable power purchase contracts will be unable to construct the renewable generating facilities by the time period 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 electric power purchase agreements, 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 13.0 percent and 13.5 percent, respectively, of our Utility Member sales in 2021 (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 or if WAPA were to no longer provide us with favorable pricing for any other reason, we would have to pay significantly higher prices to obtain this electric power, which could have an adverse effect on our results of operations. 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.

Financing Risks

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 facilities, 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 and the long lead time necessary to develop and construct new facilities and the long-term expected useful life of those facilities.

In December 2021, we received non-binding notices from three of our Utility Members that they intend to withdraw from membership in us with a January 1, 2024 withdrawal effective date representing 27.8 percent of our Utility Member sales in 2021. Although we have stated non-binding notices are defective under the contract termination payment tariff and therefore a nullity, if FERC determines that a Utility Member may provide a non-binding notice of withdraw, it will likely materially impact our long-term forecasting. See "BUSINESS — MEMBERS – Relationship with Members."

Our forecasts and actual events may vary significantly, and, as a result, we may not develop the appropriate number or type of generating facilities or rely on technology that becomes less competitive or install transmission facilities in areas where they are not needed. If we over-estimate the growth in our Utility Members' demand or Utility Members withdraw, 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 Members' demand, 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 operate in a capital-intensive industry and therefore debt comprises a majority of our capital structure.

As of December 31, 2021, we had total debt outstanding of approximately $3.2 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. 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 the Master Indenture would result in an event of default under the Master Indenture and other loan agreements. As a consequence, our results of operations, liquidity and financial condition could be adversely affected.

We expect we will need to construct or acquire additional generation, including energy storage facilities, such as batteries, and transmission facilities to meet our Utility Members' demands, to comply with new CO_2 reduction and RPS legislation, and to implement our Responsible Energy Plan and our Electric Resource Plan, which may require substantial additional capital expenditures which may 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.

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 or cyber attacks, natural disasters, and views on climate change and emissions of CO_2, 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 flows.

General Risks

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 2022 through 2026, we estimate that we may invest approximately $877 million in new facilities and upgrades to our existing facilities which may require us to take on 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 to access capital on favorable terms, or at all. These factors and disruptions include:

- market conditions generally;
- economic downturn or recession;
- instability in the financial markets;
- a tightening of lending and borrowing standards by banks and other credit providers;
- financial markets' view that climate change and emissions of CO_2 are a financial risk;
- financial markets' view of our clean energy transition and the timing of such transition;
- financial markets' view of our relationship with our Utility Members;
- 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; or
- 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 risk, including changes in interest rates and availability of capital in credit markets. The interest rates on these future borrowings could be significantly higher than interest rates on our existing debt. As of December 31, 2021, we had $499.6 million of debt with variable rates. The rates on this debt could increase.

We maintain the 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 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 borrowing under the Revolving Credit Agreement.

If we are unable to protect our information systems against service interruption, misappropriation of data or breaches of security, 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. 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. Our industry continues to see an increased volume and sophistication of cyber incidents. 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, cyber attacks 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. 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.

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 may be outsourced to third-party service providers that could also be targets of cyber attacks.

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 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. 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.

We may be subject to physical attacks.

As operators of energy infrastructure, we may face a 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.

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.

A portion of our workforce is represented by unions. Failure to successfully negotiate collective bargaining agreements, or 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 2025. Strikes or work stoppages or other business interruptions could occur if we are unable to renew these agreements on satisfactory terms or enter into new agreements on satisfactory terms or if we are unable to otherwise manage changes in, or that affect, our workforce, which could adversely impact our business, financial condition or 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 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	243	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
Rifle Generating Station	Colorado	100.0	Gas	81	81	1986

* 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 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. We intended to retire Craig Station Unit 3 by December 31, 2029.

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. Effective August 1, 2021, our ownership share in MBPP increased by 1.37 percent to 28.5 percent due to our acquisition of Wyoming Municipal Power Agency's 1.37 percent ownership share in MBPP. Our share of Laramie River Generating Station's total capacity is 484 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 and selling 100 MWs of such capacity to PNM through May 2022. 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.

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. In August 2021, we completed merging the entities that owned J.M. Shafer Generating Station, including Thermo Cogeneration Partnership, L.P., into Tri-State. Following the merger, our ownership of J.M. Shafer Generating Station is now subject to the lien of our Master Indenture.

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.

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.

Rifle Generating Station. Rifle Generating Station is an 81 MW, natural gas fired, combined-cycle generating facility located near Rifle, Colorado, which is primarily operated during periods of peak demand. Rifle Generating Station is wholly owned and operated by us.

Transmission

As of December 31, 2021, 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	3,266
138	173
230	1,198
345	1,100
Total	5,793

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 approximately 419 substations and switchyards. All of 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. New Horizon Mine is in final mine reclamation and no longer produces coal.

ITEM 3. LEGAL PROCEEDINGS

Information required by this Item is contained in "Note 15—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 45 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 42 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 became regulated as a public utility under Part II of the FPA on September 3, 2019 when we admitted a Non-Utility Member, MIECO, Inc. (non-governmental/non-electric cooperative entity), as a new Member/owner.

We supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or long-term purchase contracts with respect to various generating facilities. Our diverse generation portfolio provides us with maximum available power of 4,440 MWs, of which approximately 1,366 MWs comes from renewables. We estimate that in 2021 over a third of the energy our Utility Members used came from clean sources.

In 2021, we sold 17.6 million MWhs, of which 89.1 percent was to Utility Members. Total revenue from electric sales was $1.3 billion for the year ended December 31, 2021, of which 86.4 percent was from Utility Member sales. Our results for the year ended December 31, 2021 were primarily impacted by seasonal weather changes as well as reduced sales due to the withdrawal of DMEA and disruptions of operations from our Utility Members' commercial customers associated with the COVID-19 pandemic that have not returned.

- Utility Member electric sales decreased $34.9 million, or 2.9 percent, primarily due to reduced membership and a rate reduction in our Utility Member stated rate.
- Rate stabilization revenue increased $66.3 million, or 546.5 percent. In order to better align with our 2021 financial goals and as part of rate stabilization measures, in accordance with our Board policy, we recognized previously deferred income and revenue.
- Purchased power expense increased $45.7 million, or 13.6 percent, primarily due to decreased generation from our generating facilities because of maintenance activities and favorable market conditions for purchasing power.

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, 2021, 21 Utility Members have enrolled in this program with capacity totaling approximately 145 MWs of which 126 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 in 2019 and 2020, consisting of a representative from each Utility Member, to review the wholesale electric service contracts and to discuss alternative contracts for our Utility Members, including partial requirements contracts. Upon recommendations from the contract committee, our Board approved a community solar program, a partial requirements structure, including a buy-down payment methodology, and a methodology to calculate a contract termination payment. See "BUSINESS – MEMBERS."

Under the new partial requirements membership construct, Utility Members can 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 community solar program. During our initial "open season" partial requirements nomination period that was completed in May 2021, three Utility Members nominated and were allocated an aggregate of 203 MWs of self-supply out of an available pool of 300 MWs. No Utility Member has executed a partial requirement contract or become a Class B member. In January 2022, our Board approved an extension of the initial open season to offer the remaining 97 MWs of the 300 MWs of self-supply to the Utility Members who did not participate in 2021.

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. The modified contract termination payment methodology is 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 includes requirements for a two-year notice and the payment of a contract termination payment to us. 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 is scheduled to occur in May 2022 with an initial decision to be issued by a FERC administrative law judge by the end of July 2022. Three of our Utility Members, in December 2021, provided us a non-binding notice of their intent to withdraw from membership in us, including United Power. We filed certain answers to these non-binding notices with FERC explaining that non-binding notices are defective under the contract termination payment tariff and therefore a nullity. See "BUSINESS – MEMBERS – Relationship with Members" for additional information.

In May 2020, United Power filed a complaint for declaratory judgement and damages against us 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 wholesale electric service contract with United Power. In July 2021, the court granted United Power's motion to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add a claim that our addition of the Non-Utility Members violated Colorado law. In July 2021, we filed a partial motion to dismiss the amended May 2020 complaint. See "Note 15—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

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, including rejoining the Paris Agreement. The Biden administration has stated it has a goal to achieve a carbon pollution-free power sector by 2035 and to put the United States on a path to a net-zero economy by 2050. The Biden administration has also stated it expects to begin another, new rulemaking and has stated its intent to issue a new proposed rule in 2022 regarding emission limits and emission guidelines of CO_2 for existing generating facilities.

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 addition, in Colorado, legislation requires us to file and obtain COPUC approval for our electric resource plan and directs that such plan consider the cost of CO_2 emissions associated with our generating facilities. 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 Risk."

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. Over the past two years, we and our Utility Members have made great strides implementing the plan, which has allowed us to set new goals beyond those identified in January 2020. 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 2024, 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.
- Expanding electric vehicle infrastructure and beneficial electrification.

See "BUSINESS – MEMBERS – Responsible Energy Plan."

In December 2020, we filed our first Phase I Electric Resource Plan under the COPUC rules related to electric resource plans, which contained our Preferred Plan. In September 2021, we submitted to the COPUC our Revised Preferred Plan in connection with Phase I of our 2020 Electric Resource Plan that modeled the addition of 2,050 MWs of additional renewable resources and more than 200 MWs of electric storage during the resource acquisition period of 2021 to 2030. In January 2022, we reached a comprehensive proposed settlement agreement that was filed with the COPUC for approval and 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 COPUC is expected to consider and act on the filing in 2022. See "BUSINESS – POWER SUPPLY RESOURCES – Resource Planning."

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 which 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 the 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 the 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. We estimate that our DSR for the twelve months ended December 31, 2021 was 1.190.

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 United States) 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 the Master Indenture and restrict our ability to issue additional secured obligations under the Master Indenture. We estimate that as of December 31, 2021, our ECR was 25.06 percent.

As of December 31, 2021, 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. On November 9, 2021, U.S. Bank National Association became the successor trustee under our Master Indenture. Pursuant to the Master Indenture, DSR and ECR are calculated based on unconsolidated Tri-State financials and calculated in accordance with the system of accounts proscribed by FERC, not GAAP. 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 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 Utility 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 $499.7 million of patronage capital to our Utility Members.

Pursuant to our 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 policy establishes 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. 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. This policy had a DSR goal of 1.190 for the twelve months ended December 31, 2021 and an ECR goal of 23.5 percent as of December 31, 2021. This policy, subject to change by our Board, sets a DSR goal of 1.195 for the twelve months ended December 31, 2022 and an ECR goal of 24.0 percent as of December 31, 2022.

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. FERC 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, including our Class A wholesale rate schedule referenced below, and wholesale electric service contracts. The tariff rates were referred to an administrative law judges to encourage settlement of material issues and to hold hearings if settlements were not reached. On August 2, 2021, FERC approved our settlement agreement related to our Utility Member stated rate that provides for us to implement a two-stage, graduated reduction in the charges making up our A-40 rate of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from current rates) on March 1, 2022 until the date a new Class A wholesale rate schedule goes into effect. See "Note 15—Commitments and Contingencies—Legal" to the Consolidated Financial Statements in Item 8 for further information.

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 pursuant to our market-based rate authority.

Revenues from electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule filed with FERC. Our Class A rate schedule (A-40) for electric power sales to our Utility Members has been in effect since 2017. Our Class A rate schedule 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.

Our Class A rate schedule (A-40) was filed at FERC as a "stated rate." While our Board still has authority to determine our rates, those rates, including any change to the rate or rate structure, must be approved by FERC subject to outside comments. As part of the FERC approved settlement agreement, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule, at least through May 31, 2023. A rate design committee consisting of a representative from each Utility Member is working on the development of a new rate to our Utility Members.

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. We continually evaluate options to achieve the goal of lowering wholesale rates to our Utility Members.

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. Effective January 1, 2020, we adopted the normalization method for recognizing deferred income taxes pursuant to FERC regulation. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit). Our subsidiaries are not subject to FERC regulation and continue to use a flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues.

Results of Operations

General

Our electric sales revenues are derived from wholesale electric service sales to our Utility Members and non-member purchasers. See "—Factors Affecting Results – Rates and Regulation" for a description of our energy and demand rates to our Utility Members. Long-term contract sales to non-members generally include energy and demand components. Short-term sales to non-members are sold at market prices after consideration of incremental production costs. Demand 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;
- COVID-19 and governmental orders related to COVID-19; and
- economic conditions.

COVID-19 Impacts

We continue to experience decreased sales to our Utility Members and Utility Member revenue due to disruptions of operations from our Utility Members' industrial and commercial customers in the business of mineral extraction, natural gas, CO_2, oil production, or transportation of these. Outages at facilities of certain of these large customers due to COVID-19 has reduced demand from and energy sales to our Utility Members and such demand and energy sales have not returned. The extent to which the COVID-19 pandemic may continue to impact our results of operations, including the long-term nature of the impacts, depends on numerous evolving factors, which are highly uncertain and difficult to predict.

Year ended December 31, 2021 compared to year ended December 31, 2020

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 MWh by type of purchaser for 2021 and 2020 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2021	2020	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 1,161,291	$ 1,196,232	$ (34,941)	(2.9)%
Non-member electric sales	104,712	90,382	14,330	15.9 %
Rate stabilization	78,457	12,136	66,321	546.5 %
Other	56,341	53,545	2,796	5.2 %
Total operating revenues	$ 1,400,801	$ 1,352,295	$ 48,506	3.6 %
Energy sales (in MWh):				
Utility Member electric sales	15,676,830	15,884,777	(207,947)	(1.3)%
Non-member electric sales	1,911,059	1,609,088	301,971	18.8 %
	17,587,889	17,493,865	94,024	0.5 %

- Utility Member electric sales decreased, in terms of MWhs sold, primarily due to the withdrawal of DMEA in June 2020 and continued economic impacts of COVID-19 during the year, in particular, from our Utility Members' industrial and commercial customers. DMEA represented 3.4 percent of Utility Member revenue during the six months ended June 30, 2020. The decrease in Utility Member electric sales revenue caused by lower sales volume was slightly compounded by a 1.2 percent lower average price during the twelve months ended December 31, 2021 when compared to the same period in 2020. The decrease in average price was primarily due to a two percent settlement rate reduction to our Utility Member stated rate effective as of March 1, 2021. We expect the average price to our Utility Members to be lower in 2022 compared to 2021 due to an additional two percent rate reduction effective as of March 1, 2022.

- Rate stabilization measures are undertaken in order to better align with our financial goals and to limit rate increases from year to year by recognizing previously deferred income or revenue. In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized $78.5 million of previously deferred revenue in 2021 compared to $12.1 million during the same period in 2020.

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 2021 and 2020 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2021	2020	Amount	Percent
Operating expenses				
Purchased power	$ 381,477	$ 335,814	$ 45,663	13.6 %
Fuel	236,089	234,844	1,245	0.5 %
Production	185,016	171,188	13,828	8.1 %
Transmission	182,327	170,933	11,394	6.7 %
General and administrative	57,243	69,796	(12,553)	(18.0)%
Depreciation, amortization and depletion	190,237	185,243	4,994	2.7 %
Coal mining	5,323	11,691	(6,368)	(54.5)%
Other	7,191	15,126	(7,935)	(52.5)%
Total operating expenses	$ 1,244,903	$ 1,194,635	$ 50,268	4.2 %

- Purchased power expense increased primarily due to decreased generation from certain of our generating facilities because of scheduled maintenance as well as favorable market conditions for purchasing power during the twelve months ended December 31, 2021 compared to the same period in 2020. Generation decreased 9.8 percent during the twelve months ended December 31, 2021 compared to the same period in 2020. Purchased power increased (in MWhs) 7.2 percent for the twelve months ended December 31, 2021 compared to the same period in 2020. The average price was 3.1 percent higher during the twelve months ended December 31, 2021 compared to the same period in 2020.

- Production expense increased primarily due to the performance of scheduled maintenance postponed during the prior year as a result of COVID-19. Scheduled maintenance was performed at several generating facilities during the twelve months ended December 31, 2021, resulting in $25.3 million in increased maintenance costs compared to the same period in 2020. Maintenance expenses were slightly offset by a decrease of $11.5 million in general production expenses during the twelve months ended December 31, 2021 compared to the same period in 2020.

- General and administrative expense decreased primarily due to a decrease in outside professional services and an overall decrease in administrative expenses.

Year ended December 31, 2020 compared to year ended December 31, 2019

For discussion of our results of operations comparing the year ended December 31, 2020 to the year ended December 31, 2019, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of our 2020 Annual Report on Form 10-K, filed with the SEC on March 5, 2021.

Financial Condition as of December 31, 2021 compared to December 31, 2020

Assets

Other plant decreased $62.9 million, or 5.4 percent, to $1.094 billion as of December 31, 2021 compared to $1.157 billion as of December 31, 2020. The decrease was primarily due to a reduction in the asset retirement obligation of $39.8 million in 2021 for the Colowyo Coal South Taylor pit.

Cash and cash equivalents decreased $26.6 million, or 20.9 percent, to $100.6 million as of December 31, 2021 compared to $127.2 million as of December 31, 2020. The decrease was primarily due to patronage capital retirements paid during fiscal year 2021 of $18.1 million and principal payments of long-term debt of $94.3 million. These decreases were partially offset by an increase in commercial paper activity of $50.0 million.

Regulatory assets decreased $44.6 million, or 6.3 percent, to $665.7 million as of December 31, 2021 compared to $710.3 million as of December 31, 2020. The decrease was primarily due to amortization of $41.1 million to depreciation, amortization and depletion expense and recovered from our Utility Members through rates.

Equity and Liabilities

Patronage capital equity increased $16.4 million, or 1.7 percent, to $994.9 million as of December 31, 2021 compared to $978.5 million as of December 31, 2020. The increase was due to margins attributable to us from our Members of $26.4 million partially offset by patronage capital retirements to our Members of $10.0 million.

Long-term debt decreased $98.3 million, or 3.1 percent, to $3.102 billion as of December 31, 2021 compared to $3.200 billion as of December 31, 2020 and current maturities of long-term debt increased $5.4 million, or 6.2 percent, to $93.0 million as of December 31, 2021 compared to $87.6 million as of December 31, 2020. The net decrease of $92.9 million was primarily due to debt payments of $94.3 million (principally $41.0 million for the Springerville certificates, $22.0 million to pay off the remaining balance of the First Mortgage Obligations, Series 2009C, and $16.5 million of CoBank debt). During 2021, we repurchased and cancelled $5.3 million of our First Mortgage Bonds, Series 2014E-1, which resulted in a loss on extinguishment of debt of $0.4 million.

Short-term borrowings increased $50.0 million, or 100 percent, to $50.0 million as of December 31, 2021 compared to $0 as of December 31, 2020. The increase was due to commercial paper activity during the fourth quarter of 2021 to provide additional liquidity as Utility Members electric sales revenue was below forecast and fuel and purchased power expenses were higher than forecasted.

Regulatory liabilities decreased $79.0 million, or 35.1 percent, to $146.0 million as of December 31, 2021 compared to $225.0 million as of December 31, 2020. The decrease was primarily due to the recognition of $63.7 million of previously deferred non-member electric sales revenues and the recognition of $14.7 million of previously deferred membership withdrawal income.

Asset retirement and environmental reclamation obligations decreased $43.7 million, or 34.5 percent, to $83.3 million as of December 31, 2021 compared to $127.0 million as of December 31, 2020. The decrease was primarily due to a reduction in the Colowyo Mine reclamation liability of $45.9 million. This reduction was primarily related to a change in the mine plan of South Taylor pit at the Colowyo Mine. After obtaining regulatory approval, the South Taylor pit life was extended through 2027 to mine the highwall, which resulted in a lower estimated obligation at the end of the mining period.

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, 2021, we had $100.6 million in cash and cash equivalents. Our committed credit arrangement as of December 31, 2021 is as follows (dollars in thousands):

	Authorized Amount	Available December 31, 2021
Revolving Credit Agreement	$ 650,000 (1)	$ 600,000 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.

(2) The portion of this facility that was unavailable at December 31, 2021 was $50 million which was dedicated to support outstanding commercial paper.

We have a secured Revolving Credit Agreement with aggregate commitments of $650 million. The Revolving Credit Agreement includes a swingline sublimit of $100 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million, of which $100 million of the swingline sublimit, $75 million of the letter of credit sublimit, and $450 million of the commercial paper back-up sublimit remained available as of December 31, 2021. As of December 31, 2021, we had $600 million of availability under the Revolving Credit Agreement.

The Revolving Credit Agreement is secured under the Master Indenture and has a maturity date of April 25, 2023, unless extended as provided therein. We plan to amend and extend the Revolving Credit Agreement in the second quarter of 2022 for a period between three and five years. Funds advanced under the Revolving Credit Agreement are either LIBOR rate loans or base rate loans, at our option. LIBOR rate loans bear interest at the adjusted LIBOR rate for the term of the advance plus a margin (currently 1.125 percent) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (currently 0.125 percent) 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 one-month LIBOR rate plus 1.00 percent. When we amend and extend the Revolving Credit Agreement, we plan to remove LIBOR as a reference rate and replace it with Term SOFR. We had no outstanding borrowings as of December 31, 2021.

The 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 Revolving Credit Agreement, which was $500 million at December 31, 2021, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of December 31, 2021, we had $50 million of commercial paper outstanding (prior to netting discounts) and $450 million available on the commercial paper back-up sublimit.

We have from time to time purchased our 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 in the future. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. We are mindful of our debt and its maturities and we continually evaluate options to ensure that our balance sheet and capital structure is aligned with our business and the long-term health of our company.

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

Debt. As of December 31, 2021, we had $3.2 billion in outstanding obligations, including approximately $2.9 billion of debt outstanding under our Master Indenture, with $93.0 million payable in 2022. We have total future interest payments of $2.2 billion, with $138.8 million payable in 2022.

Construction Obligations. As of December 31, 2021, we had $46.3 million in contractual obligations to complete certain construction projects associated with our generating facilities and transmission system, with $22.4 million payable in 2022.

Coal Purchase Obligations. As of December 31, 2021, we had $166.8 million in contractual obligations to purchase coal for our generating facilities under long-term contracts that expire between 2024 and 2041, including $34.5 million payable in 2022. 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, and the Revolving Credit Agreement.

Cash Flow

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

Year ended December 31, 2021 compared to year ended December 31, 2020

Operating activities. Net cash provided by operating activities was $169.9 million in 2021 compared to $330.9 million in 2020, a decrease of $161.0 million. Substantially all of the decrease was due to proceeds related to the DMEA withdrawal in 2020 compared to no proceeds in 2021.

Investing activities. Net cash used in investing activities was $131.4 million in 2021 compared to $120.3 million in 2020, an increase of $11.1 million. The increase was primarily due to proceeds from the sale of electric plant related to the DMEA withdrawal in 2020 compared to no proceeds from the sale of electric plant in 2021. Partially offsetting this increase was a reduction in generation and transmission improvements and system upgrades in 2021 compared to 2020.

Financing activities. Net cash used in financing activities was $65.4 million in 2021 compared to $192.3 million in 2020, a decrease in net cash used in financing activities of 126.9 million. The decrease was primarily due to lower proceeds from issuance of long-term debt in 2021 compared to 2020 (during 2020, we borrowed $125 million from the First Mortgage Obligations, Series 2020A, $100 million from the First Mortgage Obligations, Series 2020B, and $200 million from our Revolving Credit Agreement). This decrease was partially offset by lower principal payments of long-term debt in 2021 compared to 2020. During 2021, we repurchased and cancelled $5.3 million of our First Mortgage Bonds, Series 2014E-1, which resulted in a loss on extinguishment of debt of $0.4 million.

Year ended December 31, 2020 compared to year ended December 31, 2019

For discussion of our cash flow comparing 2020 to 2019, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow" in Item 7 of our 2020 Annual Report on Form 10-K, filed with the SEC on March 5, 2021.

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 Responsible Energy Plan, in the years 2022 through 2026, we forecast that we may invest approximately $877 million 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):

	2022	2023	2024	2025	2026	Total
Generation	$ 22,708	$ 34,954	$ 10,512	$ 25,148	$ 26,018	$ 119,340
Transmission	118,404	107,534	149,317	123,165	120,119	618,539
General Plant	26,397	26,712	37,902	23,721	23,983	138,715
Total Capital Expenditures	$ 167,509	$ 169,200	$ 197,731	$ 172,034	$ 170,120	$ 876,594

Our actual capital expenditures depend on a variety of factors, including assumptions related to our Responsible Energy Plan and our Revised Preferred Plan in conjunction with Phase I of our 2020 Electric Resource Plan filed with the COPUC, Utility Member load growth, availability of necessary permits, regulatory changes, environmental requirements, construction delays and costs, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

Capital projects include several transmission projects to improve reliability and load-serving capability throughout our Utility Members' service territories.

Rating Triggers

Our current senior secured ratings are “A3 (stable 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 Revolving Credit Agreement includes a pricing grid related to the LIBOR 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 be significant or have a material adverse effect on our financial condition or our future results of operations.

We currently have contracts that require adequate assurance of performance. These include natural gas supply contracts, coal purchase 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 similar adequate assurance requirements. If we are required to provide such adequate assurances, we do not believe the amounts will be significant or that they will have a material adverse effect on our financial condition or our future results of operations.

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, 2021 and 2020 are as follows:

	December 31, 2021		December 31, 2020	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,214,427	$ 3,759,991	$ 3,308,715	$ 3,908,497

Commodity Price Risk

We have exposure to the market price of energy to meet obligations. We engage in structured hedging activities for both gas and electricity to mitigate exposure to market price volatility.

We have an established energy risk management program to manage risks associated with 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 would result from prolonged, unanticipated outages from our generating facilities.

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. We also have available for our use approximately 110 MWs of distillate fuel oil-only simple-cycle turbine capacity, and 353 MWs of our gas-only combined-cycle capacity, which affords substantial flexibility in meeting our obligations to serve our Utility Members. In 2021, these resources provided approximately 6.3 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.

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, 2021, we were exposed to the risk of changes in interest rates related to our $499.6 million of variable rate debt, comprised of $152.5 million of variable rate CFC notes and $297.0 million of variable rate CoBank notes. As of December 31, 2021, the weighted average interest rate on this variable rate debt was 1.50 percent.

We have plans to amend our loan documents with CFC and CoBank for LIBOR based term loans and replace the reference rate with Term SOFR prior to the discontinuation of the LIBOR rate.

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, 2021, we had 15.3 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 $4.5 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

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, 2021 and 2020, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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 – 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 estimated fair value at the time the obligations are incurred and capitalized as part of the related long-lived asset. 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 and environmental 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 of the asset retirement obligation is determined by using a present value technique which is 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 obligation 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 9, 2022

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

As of December 31,	2021	2020
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,606,732	$ 5,520,781
Construction work in progress	107,636	89,447
Total electric plant	5,714,368	5,610,228
Less allowances for depreciation and amortization	(2,367,197)	(2,279,950)
Net electric plant	3,347,171	3,330,278
Other plant	1,093,922	1,156,796
Less allowances for depreciation, amortization and depletion	(823,087)	(810,456)
Net other plant	270,835	346,340
Total property, plant and equipment	3,618,006	3,676,618
Other assets and investments		
Investments in other associations	163,097	162,975
Investments in and advances to coal mines	2,273	2,799
Restricted cash and investments	4,101	4,682
Other noncurrent assets	15,873	14,889
Total other assets and investments	185,344	185,345
Current assets		
Cash and cash equivalents	100,555	127,187
Restricted cash and investments	480	205
Deposits and advances	34,042	32,012
Accounts receivable—Members	95,630	96,637
Other accounts receivable	21,571	20,570
Electric plant held for sale	—	4,877
Coal inventory	59,701	55,762
Materials and supplies	87,234	82,119
Total current assets	399,213	419,369
Deferred charges		
Regulatory assets	665,693	710,268
Prepayment—NRECA Retirement Security Plan	16,117	21,490
Other	35,139	33,646
Total deferred charges	716,949	765,404
Total assets	**$ 4,919,512**	**$ 5,046,736**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 994,865	$ 978,519
Accumulated other comprehensive loss	(1,460)	(5,714)
Noncontrolling interest	119,100	114,851
Total equity	1,112,505	1,087,656
Long-term debt	3,101,870	3,200,181
Total capitalization	4,214,375	4,287,837
Current liabilities		
Member advances	17,217	16,592
Accounts payable	105,965	98,654
Short-term borrowings	49,997	—
Accrued expenses	32,882	40,736
Current asset retirement obligations	7,003	11,044
Accrued interest	25,716	27,520
Accrued property taxes	33,877	32,794
Current maturities of long-term debt	93,039	87,587
Total current liabilities	365,696	314,927
Deferred credits and other liabilities		
Regulatory liabilities	146,021	224,953
Deferred income tax liability	18,987	19,591
Asset retirement and environmental reclamation obligations	83,278	127,045
Other	78,319	54,600
Total deferred credits and other liabilities	326,605	426,189
Accumulated postretirement benefit and postemployment obligations	12,836	17,783
Total equity and liabilities	**$ 4,919,512**	**$ 5,046,736**

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,	2021	2020	2019
Operating revenues			
Member electric sales	$ 1,161,291	$ 1,196,232	$ 1,238,672
Non-member electric sales	104,712	90,382	89,248
Rate stabilization	78,457	12,136	6,153
Other	56,341	53,545	51,399
	1,400,801	1,352,295	1,385,472
Operating expenses			
Purchased power	381,477	335,814	328,921
Fuel	236,089	234,844	280,325
Production	185,016	171,188	209,586
Transmission	182,327	170,933	163,757
General and administrative	57,243	69,796	49,607
Depreciation, amortization and depletion	190,237	185,243	157,734
Coal mining	5,323	11,691	10,027
Other	7,191	15,126	19,090
	1,244,903	1,194,635	1,219,047
Operating margins	**155,898**	**157,660**	**166,425**
Other income			
Interest	3,609	4,218	6,175
Capital credits from cooperatives	9,466	11,803	9,799
Other	4,152	1,831	18,427
	17,227	17,852	34,401
Interest expense			
Interest	143,328	151,423	160,169
Interest charged during construction	(3,786)	(6,088)	(8,699)
	139,542	145,335	151,470
Income tax expense (benefit)	295	(534)	(307)
Net margins including noncontrolling interest	33,288	30,711	49,663
Net margin attributable to noncontrolling interest	(6,942)	(5,590)	(4,354)
Net margins attributable to the Association	**$ 26,346**	**$ 25,121**	**$ 45,309**

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,	2021	2020	2019
Net margins including noncontrolling interest	$ 33,288	$ 30,711	$ 49,663
Other comprehensive income (loss):			
Unrealized loss on securities available for sale	(108)	—	—
Unrecognized prior service credit on postretirement benefit obligation	5,698	—	—
Unrecognized actuarial gain (loss) on postretirement benefit obligation	784	625	(1,341)
Amortization of actuarial (gain) loss on postretirement benefit obligation included in net margin	78	—	(5)
Amortization of prior service cost credit on postretirement benefit obligation included in net margin	(2,139)	(79)	(79)
Unrecognized actuarial loss on executive benefit restoration obligation	(778)	(1,980)	(12)
Unrecognized prior service cost on executive benefit restoration obligation	(1,050)	(4,674)	(557)
Amortization of actuarial loss on executive benefit restoration obligation included in net margin	656	—	18
Amortization of prior service cost on executive benefit restoration obligation included in net margin	1,113	1,912	83
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	4,254	(4,196)	(1,893)
Comprehensive income including noncontrolling interest	37,542	26,515	47,770
Net comprehensive income attributable to noncontrolling interest	(6,942)	(5,590)	(4,354)
Comprehensive income attributable to the Association	**$ 30,600**	**$ 20,925**	**$ 43,416**

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,	2021	2020	2019
Patronage capital equity at beginning of period	$ 978,519	$ 1,031,063	$ 1,015,754
Net margins attributable to the Association	26,346	25,121	45,309
Retirement of patronage capital	(10,000)	(77,665)	(30,000)
Patronage capital equity at end of period	**994,865**	**978,519**	**1,031,063**
Accumulated other comprehensive income (loss) at beginning of period	(5,714)	(1,518)	375
Unrealized loss on securities available for sale	(108)	—	—
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net margin	78	—	(5)
Reclassification adjustment for prior service credit on postretirement benefit obligation included in net margin	(2,139)	(79)	(79)
Reclassification adjustment for actuarial loss on executive benefit restoration obligation included in net margin	656	—	18
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	1,113	1,912	83
Unrecognized prior service credit on postretirement benefit obligation	5,698	—	—
Unrecognized actuarial gain (loss) on postretirement benefit obligation	784	625	(1,341)
Unrecognized actuarial loss on executive benefit restoration obligation	(778)	(1,980)	(12)
Unrecognized prior service cost on executive benefit restoration obligation	(1,050)	(4,674)	(557)
Accumulated other comprehensive loss at end of period	**(1,460)**	**(5,714)**	**(1,518)**
Noncontrolling interest at beginning of period	114,851	111,717	110,169
Net comprehensive income attributable to noncontrolling interest	6,942	5,590	4,354
Equity distribution to noncontrolling interest	(2,693)	(2,456)	(2,806)
Noncontrolling interest at end of period	**119,100**	**114,851**	**111,717**
Total equity at end of period	**$ 1,112,505**	**$ 1,087,656**	**$ 1,141,262**

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,	2021	2020	2019
Operating activities			
Net margins including noncontrolling interest	$ 33,288	$ 30,711	$ 49,663
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	190,237	185,243	157,734
Amortization of intangible asset	—	—	3,662
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,372
Amortization of debt issuance costs	2,479	2,460	2,375
Impairment loss	—	274,645	37,067
Deferred impairment loss and other closure costs	—	(283,047)	(37,067)
Deferred membership withdrawal income	—	110,165	—
Deposits associated with generator interconnection requests	17,130	—	—
Rate stabilization	(78,457)	(12,136)	(6,153)
Capital credit allocations from cooperatives and income from coal mines over refund distributions	512	(1,268)	(1,276)
Changes in operating assets and liabilities:			
Accounts receivable	(3,618)	17,358	2,383
Coal inventory	(3,453)	(5,571)	5,692
Materials and supplies	(4,714)	(40)	154
Accounts payable and accrued expenses	13,114	(844)	1,136
Accrued interest	(1,804)	(2,196)	(2,354)
Accrued property taxes	1,082	3,665	547
Other	(1,261)	6,402	14,328
Net cash provided by operating activities	**169,907**	**330,919**	**233,263**
Investing activities			
Purchases of plant	(118,422)	(142,152)	(212,815)
Sale of electric plant	—	26,000	—
Changes in deferred charges	(13,054)	(4,885)	9,347
Proceeds from other investments	72	733	65
Net cash used in investing activities	**(131,404)**	**(120,304)**	**(203,403)**
Financing activities			
Changes in Member advances	183	(7,837)	(4,177)
Payments of long-term debt	(94,288)	(282,757)	(96,099)
Proceeds from issuance of long-term debt	—	425,000	34,910
Debt issuance costs	—	(637)	(13)
Change in short-term borrowings, net	49,997	(252,323)	48,178
Retirement of patronage capital	(18,067)	(70,881)	(23,303)
Equity distribution to noncontrolling interest	(2,693)	(2,456)	(2,806)
Other	(573)	(418)	(372)
Net cash used in financing activities	**(65,441)**	**(192,309)**	**(43,682)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**(26,938)**	**18,306**	**(13,822)**
Cash, cash equivalents and restricted cash and investments – beginning	**132,074**	**113,768**	**127,590**
Cash, cash equivalents and restricted cash and investments – ending	**$ 105,136**	**$ 132,074**	**$ 113,768**
Supplemental cash flow information:			
Cash paid for interest	$ 143,394	$ 152,570	$ 161,460
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 1,383	$ 440	$ (96)

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 ("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." The addition of Non-Utility Members in 2019 and specifically the addition of MIECO, Inc. on September 3, 2019 removed the exemption from the Federal Energy Regulatory Commission's ("FERC") regulation for us, thus subjecting us to full rate and transmission jurisdiction by FERC on September 3, 2019. Our stated rate to our Class A members was filed at FERC on December 23, 2019 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. See Note 15—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 2021, 2020 and 2019, total megawatt-hours sold were 17.6, 17.5 and 18.1 million, respectively, of which 89.1, 90.8 and 90.6 percent, respectively, were sold to Utility Members. Total revenue from electric sales was $1.3 billion for 2021, 2020 and 2019 of which 86.4, 92.1, and 92.8 percent in 2021, 2020 and 2019, respectively, was from Utility Member sales. Energy resources were provided by our generation and purchased power, of which 52.1, 58.2 and 61.5 percent in 2021, 2020 and 2019, 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 1,191 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 14—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 are 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.

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. There were no impairments of long-lived assets recognized in 2021. In 2020, we recognized an impairment loss of $274.6 million associated with the early retirement of the Escalante Generating Station, and in 2019, we recognized an impairment loss of $37.1 million associated with the early retirement of Nucla Generating Station. 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, meets 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 14—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, 2021	December 31, 2020
Regulatory assets		
Deferred income tax expense (1)	$ 18,742	$ 19,641
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	79,133	81,424
Goodwill – J.M. Shafer (3)	43,447	46,296
Goodwill – Colowyo Coal (4)	35,128	36,161
Deferred debt prepayment transaction costs (5)	123,674	132,302
Deferred Holcomb expansion impairment loss (6)	84,145	88,819
Unrecovered plant (7)	281,424	305,625
Total regulatory assets	665,693	710,268
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	2,818	3,293
Deferred revenues (9)	—	63,717
Membership withdrawal (10)	143,203	157,943
Total regulatory liabilities	146,021	224,953
Net regulatory asset	$ 519,672	$ 485,315

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(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 deferral of the impairment losses related to the early retirement of the Nucla and Escalante Generating Stations. The deferred impairment loss for Nucla Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $9.1 million annually through December 2022 and recovered from our Utility Members through rates. The deferred impairment loss for Escalante Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $11.3 million annually over the 25-year period ending in December 2045, which was the depreciable life of Escalante Generating Station, and recovered from our Utility Members through rates. The annual amortization approximates the formal annual Escalante Generating Station depreciation for the remaining life of the asset.

(8) 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.

(9) Represented the deferral of the recognition of non-member electric sales revenues. As of December 31, 2021, these deferred non-member electric sales revenues were fully refunded to Utility Members through reduced rates. During 2021, $63.7 million was recognized in operating revenues as part of our rate stabilization measures.

(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 in future periods. During 2021, $14.7 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 4.4 percent for 2021, 4.6 percent for 2020 and 4.7 percent for 2019. The amount of interest capitalized during construction was $3.8, $6.1 and $8.7 million during 2021, 2020 and 2019, 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 current liabilities 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, 2021	December 31, 2020
Basin Electric Power Cooperative	$ 116,826	$ 118,295
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,076	11,933
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,149	15,221
CoBank, ACB	12,985	11,141
Other	6,061	6,385
Investments in other associations	$ 163,097	$ 162,975

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 2021, 2020 or 2019.

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.

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

	December 31, 2021	December 31, 2020
Cash and cash equivalents	$ 100,555	$ 127,187
Restricted cash and investments - current	480	205
Restricted cash and investments - noncurrent	4,101	4,682
Cash, cash equivalents and restricted cash and investments	$ 105,136	$ 132,074

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 were $0.6 million and $0.5 million at December 31, 2021 and 2020, respectively.

INVENTORIES: Coal inventories at our owned generating facilities are stated at LIFO (last-in, first-out) cost and were $27.1 million and $24.2 million as of December 31, 2021 and 2020, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2021, we realized lower coal fuel expense of $0.2 million 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, 2021	December 31, 2020
Preliminary surveys and investigations	$ 12,366	$ 12,886
Advances to operating agents of jointly owned facilities	4,422	2,071
Operating lease right-of-use assets	7,529	7,985
Other	10,822	10,704
Total other deferred charges	$ 35,139	$ 33,646

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 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. 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 $28.7 million for these easements from 2022 through the individual easement terms ending between 2036 and 2040. The present value of the remaining easement payments was $19.3 million and $20.0 million as of December 31, 2021 and December 31, 2020, respectively, which is recorded as other deferred credits and other liabilities.

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, 2021	December 31, 2020
Transmission easements	$ 19,339	$ 19,983
Operating lease liabilities - noncurrent	1,622	1,590
Contract liabilities (unearned revenue) - noncurrent	3,523	3,702
Customer deposits	9,287	7,712
Financial liabilities - reclamation	13,122	12,081
OATT deposits	24,327	—
Other	7,099	9,532
Total other deferred credits and other liabilities	$ 78,319	$ 54,600

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. Other operating revenue also includes revenue from our Non-Utility Members. Wheeling revenue is earned when we charge other energy companies for transmitting electricity over our transmission lines. 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). Coal sales revenue results from the sale of coal from the Colowyo Mine and other locations to third parties. The associated Colowyo Mine expenses are included in coal mining and depreciation, amortization, and depletion expense on our consolidated statements of operations.

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. Effective January 1, 2020, we adopted the normalization method for recognizing deferred income taxes pursuant to FERC regulation. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit). Our subsidiaries are not subject to FERC regulation and continue to use a flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. 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 $2.9 and $2.2 million at December 31, 2021 and 2020, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was an expense of $0.6 million in 2021 and a credit of $0.1 million and $0.4 million in 2020 and 2019, respectively.

RECLASSIFICATIONS: Certain reclassifications have been made to the prior year financial statements to conform to the 2021 presentation.

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, 2021, 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 %	$ 3,049,233	$ (1,318,197)	$ 1,731,036
Transmission plant	1.11 %	to	2.09 %	1,879,148	(672,556)	1,206,592
General plant	1.46 %	to	9.53 %	406,693	(251,567)	155,126
Other	2.75 %	to	10.00 %	271,658	(124,877)	146,781
Electric plant in service (at cost)				$ 5,606,732	$ (2,367,197)	3,239,535
Construction work in progress						107,636
Electric plant						$ 3,347,171

At December 31, 2020, 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 %	$ 2,957,150	$ (1,187,541)	$ 1,769,609
Transmission plant	1.11 %	to	2.09 %	1,820,994	(627,330)	1,193,664
General plant	1.46 %	to	9.53 %	490,850	(341,440)	149,410
Other	2.75 %	to	10.00 %	251,787	(123,639)	128,148
Electric plant in service (at cost)				$ 5,520,781	$ (2,279,950)	3,240,831
Construction work in progress						89,447
Electric plant						$ 3,330,278

At December 31, 2021, we had $46.3 million of commitments to complete construction projects, of which approximately $22.4, $18.2 and $5.7 million are expected to be incurred in 2022, 2023 and 2024, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2021 (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 %	$ 392,397	$ 254,985	$ 39
MBPP - Laramie River Station	28.50 %	523,678	336,371	3,326
Total		$ 916,075	$ 591,356	$ 3,365

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 Colowyo Mine, a surface coal mine near Craig, Colorado and New Horizon Mine, near Nucla, Colorado. New Horizon Mine is in reclamation and no longer produces coal. The expenses related to Colowyo 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, 2021	December 31, 2020
Colowyo Mine assets	$ 376,868	$ 415,739
New Horizon Mine assets	5,061	4,389
Accumulated depreciation and depletion	(133,951)	(98,731)
Net mine assets	247,978	321,397
Non-utility assets	711,993	736,668
Accumulated depreciation	(689,136)	(711,725)
Net non-utility assets	22,857	24,943
Net other plant	$ 270,835	$ 346,340

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. New Horizon Mine started final reclamation on June 8, 2017.

Generation: We have asset retirement obligations related to equipment, dams, ponds, wells 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):

	2021	2020
Obligations at beginning of period	$ 138,089	$ 78,914
Liabilities incurred	1,475	2,527
Liabilities settled	(4,934)	(3,689)
Accretion expense	2,409	2,506
Change in cash flow estimate	(46,758)	57,831
Total obligations at end of period	$ 90,281	$ 138,089
Less current obligations at end of period	(7,003)	(11,044)
Long-term obligations at end of period	$ 83,278	$ 127,045

During 2021, we recorded a reduction of the Colowyo Mine reclamation liability of $40.7 million. This reduction was primarily related to a change in the mine plan of South Taylor pit at the Colowyo Mine. After obtaining regulatory approval, the South Taylor pit life was extended through 2027 to mine the highwall, which resulted in a lower estimated obligation at the end of the mining period. The West pit is currently in final reclamation. We continue to evaluate the Colowyo Mine and New Horizon Mine post reclamation obligations and will make adjustments to these obligations as needed.

We also have asset retirement obligations with indeterminate settlement dates. These are made up primarily of obligations attached to transmission and other easements that are considered by us to be operated in perpetuity and therefore the measurement of the obligation is not possible. A liability will be recognized in the period in which sufficient information exists to estimate a range of potential settlement dates as is needed to employ a present value technique to estimate fair value.

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, 2021 and December 31, 2020.

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 $0.7 million of this unearned revenue in 2021 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, 2021	December 31, 2020
Accounts receivable - Members	$ 95,630	$ 96,637
Other accounts receivable - trade:		
Non-member electric sales	5,684	5,231
Other	13,505	9,785
Total other accounts receivable - trade	19,189	15,016
Other accounts receivable - nontrade	2,382	5,554
Total other accounts receivable	$ 21,571	$ 20,570
Contract liabilities (unearned revenue)	$ 5,372	$ 6,025

NOTE 6 – LONG-TERM DEBT

We have $3.1 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”) except for one unsecured note in the aggregate amount of $12.0 million as of December 31, 2021. 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.

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 $650 million (“Revolving Credit Agreement”) that expires on April 25, 2023. We had no outstanding borrowings under the Revolving Credit Agreement as of December 31, 2021. As of December 31, 2021, we had $600 million in availability (including $450 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

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

	December 31, 2021	December 31, 2020
Mortgage notes payable		
3.66% to 8.08% CFC, due through 2028	$ 106,182	$ 115,583
2.63% to 4.43% CoBank, ACB, due through 2042	204,163	220,704
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	250,000	250,000
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	244,714	250,000
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	250,000	250,000
First Mortgage Bonds, Series 2010A, 6.00% due 2040	500,000	500,000
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
First Mortgage Obligations, Series 2009C, Tranche 2, 6.31%, due through 2021	—	22,000
Variable rate CFC, as determined by CFC, due through 2026	324	386
Variable rate CFC, LIBOR-based term loan, due through 2049	152,220	152,220
Variable rate CoBank, ACB, LIBOR-based term loans, due through 2044	297,039	297,039
Pollution control revenue bonds		
Moffat County, CO, 2.00% term rate through October 2022, Series 2009, due 2036	46,800	46,800
Springerville certificates		
Series B, 7.14%, due through 2033	292,985	333,983
Total long-term debt	$ 3,214,427	$ 3,308,715
Less debt issuance costs	(23,110)	(25,590)
Less debt discounts	(9,398)	(9,659)
Plus debt premiums	12,990	14,302
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,194,909	$ 3,287,768
Less current maturities	(93,039)	(87,587)
Long-term debt	$ 3,101,870	$ 3,200,181

Annual maturities of total long-term debt adjusted for debt issuance costs, discounts and premiums at December 31, 2021 are as follows (dollars in thousands):

2022	$ 93,039
2023	93,083
2024 (1)	340,787
2025	89,168
2026	90,752
Thereafter	2,488,080
	$ 3,194,909

(1) Includes $245 million bullet maturity for the First Mortgage Bonds, Series 2014 E-1.

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 Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our 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 as of and for the twelve months ended December 31 (dollars in thousands):

	2021	2020
Commercial paper outstanding, net of discounts	$ 49,997	$ —
Weighted average interest rate	0.20 %	— %

At December 31, 2021, $450 million of the commercial paper back-up sublimit remained available under the 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

In December 2020, we established 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, 2021		December 31, 2020	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 8,850	$ 8,640	$ 6,955	$ 6,955

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, 2021		December 31, 2020	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 597	$ 598	$ 491	$ 478

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 $95.3 million and $95.0 million as of December 31, 2021 and 2020, 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, 2021		December 31, 2020	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,214,427	$ 3,759,991	$ 3,308,715	$ 3,908,497

NOTE 9 – INCOME TAXES

We had no current income tax expense or benefit in 2021. We had a current income tax benefit of $0.5 million and $0.3 million in 2020 and 2019, respectively, due to our election to receive an alternative minimum tax credit refund in lieu of recognizing bonus depreciation.

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. Effective January 1, 2020, we adopted the normalization method for recognizing deferred income taxes pursuant to FERC regulation. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit).

Our subsidiaries are not subject to FERC regulation and continue to use a flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.

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

	December 31, 2021	December 31, 2020
Deferred tax assets		
Safe harbor lease receivables	$ 8,135	$ 11,604
Net operating loss carryforwards	144,602	116,430
Deferred revenues and membership withdrawal	38,784	57,704
Operating lease liabilities	114,237	123,459
Other	30,578	39,277
	336,336	348,474
Less valuation allowance	—	—
	336,336	348,474
Deferred tax liabilities		
Basis differences- property, plant and equipment	159,696	167,243
Capital credits from other associations	31,622	30,809
Deferred debt prepayment transaction costs	29,434	31,488
Operating lease right-of-use assets	130,111	133,850
Other	4,460	4,675
	355,323	368,065
Net deferred tax liability	$ (18,987)	$ (19,591)

Net deferred tax liabilities decreased by $0.6 million in 2021 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 $18.7 million and $19.6 million at December 31, 2021 and 2020, respectively.

The reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	2021	2020	2019
Federal income tax expense at statutory rate	21.00 %	21.00 %	21.00 %
State income tax expense, net of federal benefit	2.80	2.80	2.80
Patronage exclusion	(23.80)	(23.80)	(23.80)
Asset retirement obligations	42.18	(56.69)	(11.33)
Deferred revenues and membership withdrawal	72.15	(117.60)	3.23
Operating liabilities, net of right-of-use assets	4.50	21.02	11.29
Valuation Allowance	—	(121.38)	67.24
Net operating loss	(106.41)	1.46	(35.82)
Other book tax differences	(11.29)	69.88	33.39
Impairment	—	81.88	—
Regulatory treatment of deferred taxes	(1.51)	119.29	(68.68)
Effective tax rate	(0.38)%	(2.14)%	(0.68)%

We had an estimated tax loss of $115.7 million for 2021. At December 31, 2021, we have an estimated consolidated federal net operating loss carryforward of $609.6 million of which pre-2018 tax years in the amount of $444.5 million are subject to expiration periods between 2031 and 2037 and $165.1 million have no expiration. We have $359.6 million of state net operating loss carryforwards, of which $323.2 million is subject to expiration periods between 2030 and 2039 and $36.4 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 2018 forward. We do not have any liabilities recorded for uncertain tax positions.

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 $215.2 million, or 18.5 percent, of our Utility Member revenue and 15.4 percent of our total operating revenues in 2021. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues in 2021.

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):

	2021	2020	2019
Non-member electric sales:			
Long-term contracts	$ 44,383	$ 46,172	$ 47,224
Short-term contracts	60,329	44,210	42,024
Rate stabilization	78,457	12,136	6,153
Coal Sales	4,951	7,326	6,662
Other	51,390	46,219	44,737
Total non-member electric sales and other operating revenue	$ 239,510	$ 156,063	$ 146,800

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

We recognized $78.5 million of deferred non-member electric sales revenue and deferred membership withdrawal income for the year ended December 31, 2021, and $12.1 million and $6.2 million of deferred non-member electric sales revenue for the years ended December 31, 2020 and December 31, 2019, respectively, 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 $3.5 million in 2021 and $2.8 million in 2020. Rent expense is included in operating expenses on our consolidated statements of operations. As of December 31, 2021, 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, 2021	December 31, 2020
Operating leases		
Operating lease right-of-use assets	$ 9,081	$ 9,223
Less: Accumulated amortization	(1,552)	(1,238)
Net operating lease right-of-use assets	$ 7,529	$ 7,985
Operating lease liabilities – current	$ (491)	$ (526)
Operating lease liabilities – noncurrent	(1,622)	(1,590)
Total operating lease liabilities	$ (2,113)	$ (2,116)
Operating leases		
Weighted average remaining lease term (years)	5.4	7.6
Weighted average discount rate	3.79 %	3.84 %

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

Year 1	$ 447
Year 2	390
Year 3	328
Year 4	919
Year 5	92
Thereafter	641
Total lease payments	$ 2,817
Less imputed interest	(704)
Total	$ 2,113

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $7.3 million in 2021 and $6.6 million in 2020 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 14—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 – RELATED PARTIES

TRAPPER MINING, INC.: We were a member of Trapper Mining. Organized as a cooperative, Trapper Mining supplied 0.0, 25.7 and 24.7 percent in 2021, 2020 and 2019, respectively, of our coal for the Yampa Project. Our former 26.57 percent share of coal purchases from Trapper Mining was $0.0, $20.2 and $18.6 million in 2021, 2020 and 2019, respectively. In December 2020, upon termination of our coal supply agreement with Trapper Mining, we withdrew from membership in Trapper Mining. Our investment in Trapper Mining was recorded using the equity method. Our membership interest in Trapper Mining was $0.0 at December 31, 2021 and 2020, respectively.

NOTE 13 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,191 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan ("RS Plan") except for the 190 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 2021, 2020 and 2019 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 $26.7, $27.5 and $25.8 million in 2021, 2020 and 2019, 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 and other plan experience 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, 2021 and January 1, 2020, 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):

	2021	2020
Executive benefit restoration obligation at beginning of period	$ 7,379	$ 674
Service cost	440	332
Interest cost	205	434
Plan amendments - prior service cost	1,050	4,674
Benefit payments	—	(715)
Actuarial loss	778	1,980
Executive benefit restoration obligation at end of period	$ 9,852	$ 7,379
Fair value of plan assets at beginning of year	$ 6,955	$ —
Employer contributions	1,762	6,955
Actual return on plan assets	(77)	—
Fair value of plan assets at end of year	$ 8,640	$ 6,955
Net liability recognized	$ 1,212	$ 424

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 December 2020, we established 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):

	2021	2020
Accumulated other comprehensive loss at beginning of period	$ (4,873)	$ (130)
Plan amendments - prior service cost	(1,050)	(4,674)
Amortization of prior service cost into other income	1,113	1,911
Amortization of actuarial loss	515	—
Curtailment and settlement	141	—
Unrecognized actuarial loss	(778)	(1,980)
Accumulated other comprehensive loss at end of period	$ (4,932)	$ (4,873)

DEFINED CONTRIBUTION PLAN: 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. We made contributions to the plan of $3.3 million, $3.5 million, and $3.5 million in 2021, 2020, and 2019, respectively.

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, 2021, 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):

	2021	2020
Postretirement medical benefit obligation at beginning of period	$ 9,985	$ 10,195
Service cost	—	601
Interest cost	36	259
Benefit payments (net of contributions by participants)	(730)	(456)
Actuarial gain	(784)	(614)
Plan amendments	(5,698)	—
Postretirement medical benefit obligation at end of period	$ 2,809	$ 9,985
Postemployment medical benefit obligation at end of period	419	419
Total postretirement and postemployment medical obligations at end of period	$ 3,228	$ 10,404

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):

	2021	2020
Amounts included in accumulated other comprehensive income at beginning of period	$ (841)	$ (1,387)
Amortization of prior service credit into other income	(2,139)	(79)
Amortization of actuarial loss into other income	78	—
Actuarial gain	784	625
Plan amendments	5,698	—
Amounts included in accumulated other comprehensive income at end of period	$ 3,580	$ (841)

The assumptions used in the 2021 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	1.12 %
Initial health care cost trend (2018)	7.50 %
Ultimate health care cost trend	4.50 %
Year that the rate reached the ultimate health care cost trend rate	2027
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	3.48

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):

2022	$	647,045
2023		522,088
2024		437,346
2025		352,112
2026		277,960
2025 through 2029		566,923
	$	2,803,474

NOTE 14 – 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 and also entities for which we are not the primary beneficiary and therefore do not 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, 2021	December 31, 2020
Net electric plant	$ 740,135	$ 758,273
Noncontrolling interest	119,101	114,852
Long-term debt	300,220	342,355
Accrued interest	8,721	9,942

Our consolidated statements of operations include the following Springerville Partnership expenses for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Depreciation, amortization and depletion	$ 18,138	$ 18,138	$ 18,138
Interest	20,038	22,798	25,320

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.

Unconsolidated Variable Interest Entities

Western Fuels Association: WFA is a non-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which included us. In December 2020, we withdrew from membership in WFA. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in WFW. The pricing structure of the coal supply agreements with WFA were designed to recover the mine operating costs of the mine supplying the coal and therefore the coal sales agreements provide the financial support for the mine operations. There is not sufficient equity at risk for WFA to finance its activities without additional financial support. Therefore, WFA is considered a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact WFA’s economic performance (acquiring and supplying fuel resources) is held by the members who are represented on the WFA board of directors whose actions require joint approval. Therefore, since there is shared power over the significant activities of WFA, we were not the primary beneficiary of WFA and the entity is not consolidated. In December 2020, we ceased having any representation on the WFA board of directors. Our investment in WFA (including MBPP), accounted for using the cost method, was $2.1 million at December 31, 2021 and 2020 and is included in investments in other associations.

Western Fuels – Wyoming: WFW, the owner and operator of the Dry Fork Mine in Gillette, Wyoming, is organized for the purpose of acquiring and supplying coal, through long-term coal supply agreements, to be used in the production of electric energy at the Laramie River Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by Basin). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 28.50 percent undivided interest) own the remaining 25 percent of class BB shares of WFW. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Dry Fork Mine and therefore the coal supply agreements provide the financial support for the operation of the Dry Fork Mine. There is not sufficient equity at risk at WFW for it to finance its activities without additional financial support. Therefore, WFW is considered a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact WFW’s economic performance (which includes operations, maintenance and reclamation activities) is shared with the equity interest holders since each member has representation on the WFW board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of WFW and the entity is not consolidated. In December 2020, we ceased having any representation on the WFW board of directors. Our investment in WFW, accounted for using the cost method, was $0.1 million at December 31, 2021 and 2020 and is included in investments in other associations.

Trapper Mining, Inc.: Trapper Mining is a cooperative organized for the purpose of mining, selling and delivering coal from the Trapper Mine to the Craig Station Units 1 and 2 through long-term coal supply agreements. Trapper Mining is jointly owned by some of the participants of the Yampa Project. We had a 26.57 percent cooperative member interest in Trapper Mining. In December 2020, upon termination our coal supply agreement with Trapper Mining, we withdrew from membership in Trapper Mining. The pricing structure of the coal supply agreements were designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provided the financial support for the operation of the Trapper Mine. There was not sufficient equity at risk for Trapper Mining to finance its activities without additional financial support. Therefore, we considered Trapper Mining a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact Trapper Mining’s economic performance (which includes operations, maintenance and reclamation activities) was shared with the cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we were not the primary beneficiary of Trapper Mining and the entity was not consolidated. We recorded our investment in Trapper Mining using the equity method. In December 2020, we ceased having any representation on the Trapper Mining board of directors. Our membership interest in Trapper Mining was $15.9 million at December 31, 2019, and is included in investments in and advances to coal mines. We had no membership interest in Trapper Mining as of December 31, 2021 or December 31, 2020.

NOTE 15 – COMMITMENTS AND CONTINGENCIES

SALES: We have a resource-contingent power sales contract with Salt River Project Agricultural Improvement and Power District of 100 megawatts through August 31, 2036.

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, 2021, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2022	$ 34,511
2023	19,238
2024	16,520
2025	4,962
2026	5,102
Thereafter	86,482
	$ 166,815

Our coal purchases were $97.9 million in 2021, $101.2 million in 2020, and $125.4 million in 2019.

ELECTRIC POWER PURCHASE AGREEMENTS: 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 two contracts relating to WAPA's Loveland Area Projects (one which terminates September 30, 2024 and one which commences delivery on October 1, 2024 and terminates September 30, 2054) and three contracts relating to WAPA's Salt Lake City Area Integrated Projects (two which terminate September 30, 2024 and one which commences delivery on October 1, 2024 and terminates September 30, 2057).

As of December 31, 2021, we have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,521 MWs, including 674 MWs of wind-based power purchase agreements and 820 MWs of solar-based power purchase agreements that expire between 2030 and 2042.

Costs under the above electric power purchase agreements for the years ended December 31 were as follows (dollars in thousands):

	2021	2020	2019
Basin	$ 146,532	$ 152,461	$ 145,008
WAPA	70,107	72,491	72,504
Renewables, other than WAPA	71,565	69,255	63,677

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 and Declaratory Order. Because of increased pressure by states to regulate our rates and charges with impact in other states setting up untenable conflict, we sought consistent federal jurisdiction by FERC. This was accomplished with the addition of non-cooperative members in 2019, specifically MIECO, Inc. as a Non-Utility Member on September 3, 2019. On the same date, 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. In addition, on December 23, 2019, we filed our Petition for Declaratory Order ("Jurisdictional PDO") with FERC, EL20-16-000, asking FERC to confirm our jurisdiction under the Federal Power Act and that FERC's jurisdiction preempts the jurisdiction of the Colorado Public Utilities Commission ("COPUC") to address any rate related issues, including the complaints filed by United Power and La Plata Electric Association ("LPEA") with the COPUC.

On March 20, 2020, FERC issued orders regarding our Jurisdictional PDO and our tariff filings. FERC's orders generally accepted our tariff filings and recognized that we became FERC jurisdictional on September 3, 2019. FERC 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. The tariff rates were referred to an administrative law judges to encourage settlement of material issues and to hold hearings if settlements were not reached. On April 30, 2021, we filed a proposed settlement agreement with FERC related to our Utility Member stated rate for approval, as further discussed below. On October 22, 2021, we filed a proposed settlement agreement with FERC related to our transmission service rates for approval, as further discussed below. FERC's March 20, 2020 order regarding our Jurisdictional PDO denied our requested declaration regarding the preemption of the United Power and LPEA proceeding at the COPUC stating the proceeding is not currently preempted.

On July 17, 2020, United Power filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court of Appeals") related to FERC's March 20, 2020 order related to our Utility Member rates, USCA Case#20-1258, and such matter is being held in abeyance pending resolution of the Jurisdictional PDO appeal discussed below.

On August 28, 2020, FERC issued an order ("August 28 Order") on rehearing related to our Jurisdictional PDO which modified its March 20, 2020 decision by finding exclusive jurisdiction over our contract termination payments and preempting the jurisdiction of the COPUC as of September 3, 2019. On December 16, 2020, United Power filed a petition for review with the D.C. Circuit Court of Appeals related to FERC's August 28 Order, USCA Case#20-1256. Petitions for review related to both the Jurisdictional PDO and tariff filings have been filed with the D.C. Circuit Court of Appeals by other parties.

FERC, United Power, and the other parties reached agreement on the procedures and schedule for the Jurisdictional PDO filed with the D.C. Circuit Court of Appeals. On June 7, 2021, United Power filed its brief with the D.C. Circuit Court of Appeals regarding the Jurisdictional PDO. On September 27, 2021, FERC filed its brief with the D.C. Circuit Court of Appeals regarding the Jurisdictional PDO. On December 23, 2021, an order was issued by the court to hold all the cases before the D.C. Circuit Court of Appeals in abeyance other than related to the Jurisdictional PDO, directing the parties to file motions to govern future proceedings by March 23, 2022.

On April 30, 2021, we filed a proposed settlement agreement for approval with FERC related to our Utility Member 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 resolves all issues set for hearing and settlement procedures related to our Utility Member rates. The settlement provides for us to implement a two-stage, graduated reduction in the charges making up our Class A rate schedule of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from current rates) thereafter until the date a new Class A wholesale rate schedule is approved by FERC and goes into effect. The settlement rates will remain in effect at least through May 31, 2023 and during such time period, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule. We have also agreed to file a new Class A rate schedule after May 31, 2023 and prior to September 1, 2023. During the moratorium, we have established a rate design committee to oversee the development of the new rate. Three of the reserved issues are 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 will have prospective effect only, with the intent that any FERC rulings would be implemented in future rate filings. On August 2, 2021, FERC approved this settlement agreement. In December 2021, the administrative law judge adopted a procedural schedule on the four reserved issues with a hearing to occur in March 2022 and an initial decision to be issued by an administrative law judge by the end of May 2022.

On October 22, 2021, we filed a proposed settlement agreement for approval with FERC related to our transmission service rates, including our open access transmission tariff and annual transmission revenue requirements. The settlement resolves all issues set for hearing and settlement procedures related to our transmission service rates. The settlement agreement provides for us to refund amounts collected more than the amounts agreed to in the settlement agreement beginning March 26, 2020 upon FERC approval of the settlement agreement. We also filed a motion with FERC's Chief Judge seeking authorization to implement our reduced transmission service rates and annual transmission revenue requirements for the 2021 rate year beginning on October 1, 2021 pending FERC approval of the settlement agreement. On October 28, 2021, the Chief Judge issued an order granting implementation of the proposed reduced settlement rates effective as of October 1, 2021 pending FERC's consideration of the settlement agreement. On December 7, 2021, the Chief Judge terminated the settlement judge procedures for our transmission rates dockets. On March 7, 2022, FERC approved this settlement agreement. In connection with the settlement agreement, our other revenue and results of operations does not include our estimate of revenue that will be refunded. Such amount is being held in reserve.

It is not possible to predict the outcome of the four reserved issues related to our member rates docket or if FERC will require us to refund amounts related to the one reserved issue regarding transmission demand charges applicable to certain electric storage resources. In addition, we cannot predict the outcome of any petitions for review filed with the D.C. Circuit Court of Appeals.

LPEA and United Power COPUC Complaints. Pursuant to our Bylaws, a Utility 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 Utility Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. On November 5, 2019, LPEA filed a formal complaint with the COPUC alleging that we hindered LPEA's ability to seek withdrawal from us. On November 6, 2019, United Power filed a formal complaint with the COPUC, alleging that we hindered United Power's ability to explore its power supply options by either withdrawing from us or continuing as a Utility Member under a partial requirements contract. On November 20, 2019, the COPUC consolidated the two proceeding into one, 19F-0621E.

A hearing was held on May 18-20, 2020. On July 10, 2020, the administrative law judge issued a recommended decision, but the COPUC on its own motion stayed the recommended decision. On September 18, 2020, LPEA and United Power filed a Joint Motion to Lodge FERC's August 28 Order, and asserting additional corporate law arguments related to the legality of our addition of Non-Utility Members. On October 22, 2020, the COPUC determined that COPUC's jurisdiction over United Power and LPEA's complaints was preempted by FERC, the COPUC does not have jurisdiction over corporate law matters, and dismissed both complaints without prejudice. On January 27, 2021, United Power filed a Writ for Certiorari or Judicial Review, an appeal, in the Denver County District Court, 2021CV30325, of the COPUC's decision to dismiss United Power's complaint. On February 17, 2021, the Denver County District Court granted our unopposed motion to intervene as a defendant in United Power's appeal of the COPUC's dismissal. United Power, the COPUC, and us have all filed respective briefs with the court. The court heard oral arguments on September 17, 2021. It is not possible to predict the outcome in this matter.

United Power's Adams District Court Complaints: On May 4, 2020, United Power filed a Complaint for Declaratory Judgement and Damages with the Adams County District Court, 2020CV30649, against us and our three Non-Utility Members 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, the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula are also void, that we have breached the wholesale electric service contract with United Power, and that we and our three Non-Utility Members conspired to deprive the COPUC of jurisdiction over the contract termination payment of our Colorado Utility Members. On June 20, 2020, we filed our answer denying United Power's allegations and request for relief, and asked the court to dismiss United Power's claims. We asserted counterclaims against United Power, and are seeking relief from United Power's breach of our Bylaws and declaratory judgement that the April 2019 Bylaws amendment and the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula are valid. On June 20, 2020, the three Non-Utility Members filed a joint motion to dismiss.

On December 10, 2020, the Non-Utility Members motion to dismiss was granted. On December 23, 2020, United Power sought to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add a claim that our addition of the Non-Utility Members violated Colorado law. On July 2, 2021, the court granted United Power's motion to amend its May 2020 complaint, including to add LPEA as an additional plaintiff and to amend its claims as to our three Non-Utility Members. On July 30, 2021, we filed a partial motion to dismiss a majority of United Power's and LPEA's claims, including claims related to the April 2019 Bylaws amendment, the April 2020 Board approvals, and that we conspired with our Non-Utility Members. On July 30, 2021, the three Non-Utility Members filed a joint motion to dismiss all claims by United Power and LPEA against the Non-Utility Members. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

TAPP Complaint: On September 24, 2021, TransAmerican Power Products, Inc. (“TAPP”) filed a complaint with Adams County District Court, 2021CV31089, against us alleging breach of contract and breach of implied covenant of good faith and fair dealing related to an invoice for TAPP’s supply of materials for a transmission project. TAPP seeks damages of approximately $3 million. On November 9, 2021, we filed an answer and counterclaims against TAPP disputing any amount is owed to TAPP and seeking damages for TAPP's breach of contract. A jury trial is scheduled for April 2023. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

Basin Complaint: On December 17, 2021, Basin filed a complaint with the United States District Court District of North Dakota Eastern Division, 3:21-cv-00220-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 with Basin for the Eastern Interconnection. Basin seeks, among other things, for the court to require us to amend our modified contract termination payment tariff to exclude our Eastern Interconnection Utility Members. On January 25, 2022, we filed a motion to dismiss. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

NOTE 16 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 9, 2022, 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, 2021 our disclosure controls and procedures are effective.

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, 2021. 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 this assessment, management believes that we maintained effective internal control over financial reporting as of December 31, 2021.

Changes in Internal Control over Financial Reporting

There were no changes that occurred during the fourth quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

As a result of COVID-19, we have activated established programs and procedures to mitigate the impacts of pandemics. While certain of our employees are telecommuting, our business continuity plans have resulted in slight changes to our processes, including how employees access our systems and approve certain work. Management believes it is taking the necessary steps to monitor and maintain appropriate internal controls over financial reporting at this time.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

Our Board is comprised of one representative from each of our 42 Utility Members. 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. 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 its 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, 2022 are as follows:

NAME	AGE	UTILITY MEMBER - REPRESENTATIVE
Timothy A. Rabon—Chairman and President	61	Otero County Electric Cooperative, Inc.
Donald Keairns—Vice Chairman	62	San Isabel Electric Association, Inc.
Julie Kilty—Secretary	63	Wyrulec Company
Stuart Morgan—Treasurer	75	Wheat Belt Public Power District
Matt M. Brown—Assistant Secretary	70	High Plains Power, Inc.
Scott Wolfe—Assistant Secretary	58	San Luis Valley Rural Electric Cooperative, Inc.
Arthur W. Connell—Executive Committee	68	Central New Mexico Electric Cooperative, Inc.
Thaine Michie—Executive Committee	81	Poudre Valley Rural Electric Association, Inc.
Douglas Shawn Turner—Executive Committee	60	The Midwest Electric Cooperative Corporation
Charles Abel II	53	Sangre de Cristo Electric Association, Inc.
Leroy Anaya	65	Socorro Electric Cooperative, Inc.
Robert Baca	57	Mora-San Miguel Electric Cooperative, Inc.
Lucas Bear	41	Northwest Rural Public Power District
Robert Bledsoe	72	K.C. Electric Association
Lawrence Brase	75	Southeast Colorado Power Association
Leo Brekel	70	Highline Electric Association
William Bridges	61	Big Horn Rural Electric Company
Jerry Burnett	75	High West Energy, Inc.
Kevin Cooney	66	San Miguel Power Association, Inc.
Mark Daily	59	Gunnison County Electric Association, Inc.
Raymond Bruce Duran	59	Jemez Mountains Electric Cooperative, Inc.
Jerry Fetterman	66	Empire Electric Association, Inc.
John "Jack" Finnerty	82	Wheatland Rural Electric Association
Joel Gilbert	63	Southwestern Electric Cooperative, Inc.
Rick Gordon	68	Mountain View Electric Association, Inc.
Randolph "Randy" Graff	67	Morgan County Rural Electric Association
Ronald Hilkey	82	White River Electric Association, Inc.
Ralph Hilyard	83	Roosevelt Public Power District
Hal Keeler	93	Columbus Electric Cooperative, Inc.
Brian McCormick	46	United Power, Inc.
Kohler McInnis	67	La Plata Electric Association, Inc.
Stanley Propp	75	Chimney Rock Public Power District
Steve M. Rendon	67	Northern Rio Arriba Electric Cooperative, Inc.
Claudio Romero	75	Continental Divide Electric Cooperative, Inc.
Peggy A. Ruble	68	Garland Light & Power Company
Roger Schenk	58	Y-W Electric Association, Inc.

Gary Shaw	67	Springer Electric Cooperative, Inc.
Darryl Sullivan	71	Sierra Electric Cooperative, Inc.
Clay Thompson	63	Carbon Power & Light, Inc.
Carl Trick II	74	Mountain Parks Electric, Inc.
William Wilson	67	Niobrara Electric Association, Inc.
Phillip Zochol	46	Panhandle Rural Electric Membership Association

Timothy A. Rabon has served on our Board since April 2014 and has been Chairman and President of the Board since August 2021. Prior to serving as Chairman and President of the Board, he served as Vice-Chairman of the 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 the 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 currently owns and manages 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 the Board. She is a member of the Executive Committee and the Finance and Audit Committee. Ms. Kilty serves as Secretary of Wyrulec Company. She is owner of Bar X Ranch, LLC.

Stuart Morgan has served on our Board since May 2007 and is Treasurer of the 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.

Matt M. Brown has served on our Board since April 2010 and is Assistant Secretary of the Board. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Brown serves as a director of High Plains Power, Inc. He is a rancher in Thermopolis, Wyoming and has held a real estate license in Wyoming since 1983.

Scott Wolfe has served on our Board since June 2008 and is Assistant Secretary of the 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 farmer and owner of Lobo Farm LLC.

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

Thaine Michie has served on our Board since March 2009. He is a member of the Executive Committee and serves as Chairman of the External Affairs-Member Relations 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.

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.

Charles Abel II has served on our Board since April 2019. He is a member of 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.

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 recently retired from the Socorro County Assessor's office.

Robert Baca has served on our Board since June 2016. He is a member 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 since 1992.

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 serves as Chairman 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.

Jerry Burnett has served on our Board since November 2013. He is a member of the Engineering and Operations Committee. Mr. Burnett serves as Vice President of High West Energy, Inc. He is a real estate broker, as well as a farmer, rancher and dairyman in Hereford, Colorado. Mr. Burnett is also on the board of directors of Coldwell Banker and TPE.

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.

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

Raymond Bruce Duran has served on our Board since August 2021. He is a member of the External Affairs-Member Relations Committee. Mr. Duran serves as a trustee of Jemez Mountains Electric Cooperative, Inc. He is the owner and general manager of Construction Services Southwest LLC, which is a mechanical, utility and plumbing company.

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.

John "Jack" Finnerty has served on our Board since April 1988. He is a member of the Engineering and Operations Committee. Mr. Finnerty serves as Secretary/Treasurer of Wheatland Rural Electric Association. He is a rancher in Wheatland, Wyoming.

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.

Randolph Graff has served on our Board since April 2020. He is a member of the Engineering and Operations Committee. Mr. Graff serves as Chairman of Morgan County Rural Electric Association. He is a retired owner and operator of Graff's Turf Farms, Inc.

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 the previous owner of Adams Lodge Outfitters.

Ralph Hilyard has served on our Board since April 2002. He is a member of the Engineering and Operations Committee. Mr. Hilyard serves as a director of Roosevelt Public Power District. He is a retired self-employed farmer.

Hal Keeler has served on our Board since July 2000. He is a member of the Finance and Audit Committee. Mr. Keeler serves as a trustee of Columbus Electric Cooperative, Inc. He is a retired farm owner-operator and has also been a bank board member for 1st New Mexico Bank.

Brian McCormick has served on our Board since January 2020. He is a member of the External Affairs-Member Relations Committee. Mr. McCormick serves as a director of United Power, Inc. He owns and operates Saint Vrain Capital, LLC. He is a veteran of the U.S. Army and Colorado Army National Guard.

Kohler McInnis has served on our Board since May 2020. He is a member of the External Affairs-Member Relations Committee. Mr. McInnis serves as a director of La Plata Electric Association, Inc. Mr. McInnis is a managing member of multiple investment portfolios and is the owner of Kohler McInnis Property.

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 is currently the 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.

Claudio Romero has served on our Board since June 2001. He is a member of the Finance and Audit Committee. Mr. Romero serves as a trustee of Continental Divide Electric Cooperative, Inc. He is recently retired from electrical construction.

Peggy A. Ruble has served on our Board since April 2017. She is a member of the External Affairs-Member Relations 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 Schenk has served on our Board since April 2019. He is a member of the Finance and Audit Committee. Mr. Schenk serves as President of Y–W Electric Association, Inc. He is owner and operator of Schenk Family Farm.

Gary Shaw has served on our Board since June 2019. He is a member of the External Affairs-Member Relations 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.

Clay Thompson has served on our Board since July 2020. He is a member of the External Affairs-Member Relations Committee. Mr. Thompson serves as a director for Carbon Power & Light, Inc. Mr. Thompson is a civil engineering technician for the USDA Natural Resources Conservation Service and manages the family ranch in Laramie, Wyoming.

Carl Trick II has served on our Board since September 2012. He is a member of the Engineering and Operations Committee. Mr. Trick serves as a director of Mountain Parks Electric, Inc. He is the President and owner of North Park Angus Ranch, Inc., a cattle and hay operation in North Park, Colorado.

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 each of our Class A members and Class B members that purchase at least 65 percent of capacity from us. 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, 2022:

NAME	AGE	POSITION
Duane Highley	60	Chief Executive Officer
Joel Bladow	62	Senior Vice President, Transmission
Patrick L. Bridges	63	Senior Vice President/Chief Financial Officer
Elda de la Peña	57	Senior Vice President, People and Culture/Chief Human Resource Officer
Jennifer Goss	52	Senior Vice President, Chief Technology Officer and Member Relations
Barry Ingold	58	Senior Vice President, Generation
Bradford Nebergall	63	Senior Vice President, Energy Management
Kenneth V. Reif	70	Senior Vice President, General Counsel
Reginal "Reg" Rudolph	53	Chief Energy Innovations Officer
Barbara Walz	59	Senior Vice President, Policy & Compliance/Chief Compliance 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 39 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.

Joel Bladow is our Senior Vice President, Transmission and has served in that position since 2006. Prior to joining Tri–State, Mr. Bladow served in various executive positions as a member of WAPA's executive management team and has over 40 years of experience in the electric utility industry. Mr. Bladow has a master's degree in electrical engineering and is a registered professional engineer in Colorado.

Patrick L. Bridges is our Senior Vice President/Chief Financial Officer and has served in that position since 2008. Mr. Bridges previously served as Senior Manager, Corporate Finance. Prior to joining Tri–State in 2006, he served as the Vice President and Treasurer of Texas-New Mexico Power Company. Mr. Bridges has over 39 years of experience in the electric energy sector. He has a Master of Science degree in applied economics from the University of Texas at Dallas, a Master of Business Administration and a Bachelor of Business Administration degree from West Texas State University, and is a Certified Public Accountant, inactive, and Chartered Financial Analyst.

Elda de la Peña is our Senior Vice President, People and Culture/Chief Human Resource Officer and has served in that position since May 2021. Ms. de la Peña's title changed from Vice President, People and Culture/Chief Human Resource Officer when she assumed additional responsibilities including management of the payroll department. 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.

Jennifer Goss is our Senior Vice President, Chief Technology Officer and Member Relations and has served in that position since 2013. In June 2020, Mrs. Goss assumed additional responsibilities and her title changed from Senior Vice President, Member Relations to her current title. Prior to joining Tri-State, Mrs. Goss served from 2011 to 2013 as chief operating officer and chief financial officer for Green Energy Corp. Mrs. Goss previously served at CoBank, joining the bank in 1998 and serving as senior vice president of the electric distribution lending division and a member of the senior leadership team since 2003. She has held various positions at Fleet Financial Group and Phoenix Home Life Insurance Company. Mrs. Goss has a bachelor's degree in English literature from Assumption College. Mrs. Goss has 23 years of electric utility experience.

Barry Ingold is our Senior Vice President, Generation and has served in that position since 2014. Mr. Ingold previously served as Senior Manager, Production Assets and has served in numerous engineering and management roles since joining Tri-State in 2004. In addition to his 24 years of direct industry experience, Mr. Ingold served for 13 years in the submarine force of the United States 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 United States Navy. Mr. Ingold has a bachelor's degree in marine engineering and marine transportation from the United States 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.

Bradford Nebergall is our Senior Vice President, Energy Management and has served in that position since 2008. Prior to joining Tri–State in 2007, Mr. Nebergall was the chief operating officer for Enron Renewable Energy Corp. He also held various positions at Enron Corp. and Norwest Bank (now Wells Fargo Bank). Mr. Nebergall has a Master's of Business Administration degree from the University of Houston and a Bachelor of Science degree in finance from Iowa State University. Mr. Nebergall has 35 years of experience in the energy industry.

Kenneth V. Reif is our Senior Vice President, General Counsel and has served in that position since 2004. Prior to joining Tri–State, Mr. Reif was Director of Colorado Office of Consumer Counsel representing residential, small business and agricultural utility consumers before the COPUC and federal regulators. Prior to 1996, he practiced utility law in Denver, Colorado, first as a partner at Kelly, Stansfield and O'Donnell, and then as counsel at LeBoeuf, Lamb, Greene and MacRae. Mr. Reif has a Bachelor of Arts degree from California Polytechnic State University and a Jurisprudence Doctor degree from the University of Denver. He has 42 years of utility experience.

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 13 years and has over 30 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.

Barbara Walz is our Senior Vice President, Policy & Compliance/Chief Compliance Officer and has served in that position since 2011. She joined Tri-State in 1997 as senior engineer of environmental services. She has held various positions at Tri–State, including Environmental Services Manager and later, Vice President of Environmental. Mrs. Walz has a Bachelor of Science degree in chemical engineering from the University of North Dakota, a master's degree in environmental policy and management from the University of Denver, and a certificate in Financial Success for Nonprofits from Cornell University. In 2017, Mrs. Walz was inducted in to the University of North Dakota Engineering Hall of Fame. She has 25 years of experience in the utility industry.

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 the Board approves such compensation. The 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. The 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 the 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 the 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 the Board its inclusion in this annual report on Form 10-K.

Executive Committee Members:

Timothy A. Rabon
Donald Keairns
Julie Kilty
Stuart Morgan
Matt M. Brown
Scott Wolfe
Arthur W. Connell
Thaine Michie
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 the Board approves the compensation. The 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, Matt M. Brown, Scott Wolfe, Arthur W. Connell, Thaine Michie 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. Brown 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 2021.

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 2021). 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 (1)	Total
Duane D. Highley(2)	2021	$ 1,421,924	$ 2,213,191	$ 65,068	$ 3,700,183
Chief Executive Officer	2020	1,350,000	2,076,328	49,596	3,475,924
	2019	1,043,482	877,155	121,078	2,041,715
Patrick L. Bridges (3)	2021	502,770	—	62,780	565,550
Senior VP/CFO	2020	496,884	463,739	162,430	1,123,053
	2019	445,209	105,878	50,194	601,281
Barbara Walz	2021	413,838	576,076	43,917	1,033,831
Senior VP, Policy and	2020	367,427	591,192	117,246	1,075,865
Compliance/CCO	2019	326,090	36,563	37,926	400,579
Barry Ingold	2021	402,217	464,036	39,236	905,489
Senior VP, Generation	2020	398,400	517,490	120,413	1,036,303
	2019	369,677	136,107	27,493	533,277
Joel Bladow	2021	423,343	362,172	49,505	835,020
Senior VP, Transmission	2020	429,677	428,918	132,557	991,152
	2019	373,885	75,998	38,158	488,041

(1) 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) contribution, group term life, and employer paid premium for medical and dental insurance.

(2) Duane Highley became an employee and Chief Executive Officer in April 2019.

(3) Patrick 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.

Defined Benefit Plan

The following table lists the estimated values under the RS Plan and both restoration plans as of December 31, 2021. As a result of changes in Internal Revenue Service regulations, the annual base salary used in determining benefits is limited to $290,000 effective January 1, 2021.

Name	Number of years Credited Service as of December 31, 2021	RS Plan Present Value of Accumulated Benefit as of December 31, 2021	Pension Restoration Plans Present Value of Accumulated Benefit as of December 31, 2021	Payments During 2021
Duane D. Highley (1)	2 year, 9 months	$ 2,752,638	$ 4,611,103	None
Patrick L. Bridges (2)	11 months	97,534	937,844	$ 1,456,190
Barbara Walz	24 years, 1 month	2,478,996	434,231	None
Barry Ingold	16 years, 0 months	1,689,526	540,980	None
Joel Bladow	14 years, 1 month	1,528,330	489,366	None

(1) Mr. Highley began employment with us on April 1, 2019. He has 2 years 9 months of service with us and a total of 37 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 14 years, 3 months.

There is a one year waiting period after commencement of employment before participants are eligible for the RS Plan. This waiting period is waived if the participant was previously eligible for the RS Plan at another participating employer.

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, 2021.

Chief Executive Officer Pay Ratio

The 2021 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		2021 Total Compensation (1)
Median annual total compensation of all employees (excluding Chief Executive Officer)	$	191,622
Annual Total Compensation of Duane D. Highley, Chief Executive Officer		3,700,183
Ratio of the median annual total compensation of all employees to the annual total compensation of Duane D. Highley, Chief Executive Officer		1.0:19.3

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(1) Includes change in pension value from 2020 to 2021.

In determining the median employee, a listing was prepared of all active employees of us and our subsidiaries as of December 31, 2021. 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 2021. We determined the compensation of our median employee by (1) utilizing the W-2 Box 5 wages for all active employees for 2021 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 a material difference in the pension value of the years of benefit service of the seven employees. Therefore, we did 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 the Board

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

1) Director allowances are paid to the Chairman and President based on the requirement that the Chairman and President is required to participate in Tri-State activities or be available for consultation for 260 days per year.

The allowance for each day is $625. 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

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

1) The allowance for attendance of a director at a regular or special meeting of the Board is $500 for each day of meeting.

2) The allowance for attendance of a director at any other meeting on Tri-State business is $500 for each day of meeting.

3) The allowance for travel time for directors going to and from the above meetings, where one or more days or a partial day of travel is required in addition to the day of the meeting, is $500 for each such day.

4) There is no allowance for telephone conference or virtual meetings, unless approved by the Chairman and President.

5) Directors are reimbursed for transportation in connection with the foregoing meetings and functions at the published maximum IRS approved mileage rate for use of a personal vehicle, or for the actual commercial plane, bus, rail, and taxi fares incurred. Transportation by any other means is reimbursed at the equivalent rates for the use of a personal vehicle, or where appropriate, the commercial plane fare.

6) The allowance for meal and hotel expenses of a director incurred in the Denver metropolitan area in connection with attendance at a regular, special, or committee meeting of the Board or other authorized meetings and functions is at the published maximum IRS allowable per diem rate, for the Denver metropolitan area. 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 the Board or the Chairman and President, or in the absence of those, with the authorization of the Chief Executive Officer upon consultation with and consent of any member of the Executive Committee.

The Chairman and President has approved allowance for directors for telephone conference or virtual meetings during COVID-19.

Deferred Compensation Program

The Board, including the Chairman and President of the Board, are eligible to participate in the Directors' Elective Deferred Fees Plan. This program allows for deferral of director's fees into an unfunded and unsecured plan under Section 409A of the Internal Revenue Code. Under this program, 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 the Board in 2021 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	2021 Board Fees(1)
Charles Abel	$ 18,750
Leroy Anaya	16,000
Robert Baca	18,000
Lucas Bear	17,000
Robert Bledsoe	21,000
Lawrence Brase	24,000
Leo Brekel	16,500
William Bridges	21,000

Matt M. Brown	18,500
Jerry Burnett	15,750
Arthur W. Connell	26,500
Kevin Cooney	16,250
Lucas Cordova Jr. (4)	12,000
Mark Daily	16,000
Bruce Duran	6,500
Jerome Fetterman	13,500
John "Jack" Finnerty	19,500
Joel Gilbert	19,000
Rick Gordon (2) (3)	161,625
Randolph Graff	19,000
Ronald Hilkey	17,000
Ralph Hilyard	13,000
Donald Keairns	27,250
Hal Keeler	15,500
Julie Kilty	27,750
Brian McCormick	17,000
Kohler McInnis	18,000
Thaine Michie	26,000
Stuart Morgan	23,000
Stanley Propp	17,000
Timothy A. Rabon (2)	80,750
Steve Rendon	18,000
Claudio Romero	11,000
Peggy Ruble	14,500
Roger Schenk	15,500
Gary Shaw	17,000
Darryl Sullivan	23,000
N. Clay Thompson	15,500
Carl Trick II	15,000
Shawn Turner	26,500
William Wilson	15,000
Scott Wolfe	16,000
Phillip Zochol	9,750

(1) Various directors have deferred a total of $53,050 of the actual Board fee payments made in 2021. Some directors deferred up to 100 percent of their fee payments.

(2) Includes use of a company vehicle while Chairman and President which is grossed up to cover taxes.

(3) Includes $53,000, as the estimated value of the company vehicle that was used by Mr. Gordon while Chairman and President and gifted to Mr. Gordon upon his retirement from such position.

(4) Individual ceased serving on the Board prior to December 31, 2021.

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 2021.

Other than as described above, in 2021, 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 the 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.

	2021	2020
Audit Fees(1)	$ 780,000	$ 821,000
Audit-Related Fees(2)	—	—
Tax Fees(3)	27,000	51,000
All Other Fees(4)	—	—
Total	$ 807,000	$ 872,000

(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 2020 and 2021.

(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 the 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 the Board. Committee review and Board pre-approval is granted usually at regularly scheduled meetings. During 2020 and 2021, 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 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 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 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 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 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 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.)
4.2†	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*	Loan Agreement, dated April 10, 1992, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.7.2*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9040, in the original principal amount of $32,224,821
4.8.1*	Master Loan Agreement, dated March 14, 1997, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.8.2*	First Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated March 14, 1997
4.8.3*	Secured Promissory Note, dated March 14, 1997, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9044, in the original amount of $15,600,000
4.8.4*	Second Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated January 26 1999
4.8.5*	Secured Promissory Note, dated January 26, 1999, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9046, in the original amount of $1,172,665.68
4.9.1*	Term Loan Agreement, dated December 6, 2012, between Tri-State and CoBank, ACB
4.9.2*	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
4.10.1*	Unsecured Term Loan Agreement, dated June 10, 2013, between Tri-State and CoBank, ACB
4.10.2*	Promissory Note, dated June 10, 2013, from Tri-State to CoBank, ACB, related to Loan No. 002713681, in the original amount of $71,000,000
4.11.1*	Term Loan Agreement, dated October 31, 2014, between Tri-State and CoBank, ACB
4.11.2*	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
4.11.3*	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
4.12.1*	Term Loan Agreement, dated December 11, 2018, between Tri-State and CoBank, ACB
4.12.2*	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
4.12.3*	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
4.13.1*	Term Loan Agreement, dated June 24, 2020, between Tri-State and CoBank, ACB
4.13.2*	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
4.14.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.14.2*	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
4.15.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.15.2*	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
4.16.1*	Loan Agreement, dated June 24, 2020, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.16.2*	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
4.16.3*	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

4.17*	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 as (succesor) trustee, in the original amount of $46,800,000 related to Pollution Control Refunding Revenue Bonds, Series 2009B.
4.18.1*	Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement
4.18.2*	Notes, dated December 12, 2017, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement
4.18.3*	Notes, dated April 12, 2018, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement
4.19*	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
4.20.1*	Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of $400,000,000
4.20.2*	Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of $100,000,000
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.)
10.4†	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.)
10.6.1†	Supplemental Master Mortgage Indenture No. 23, dated as of June 8, 2010, between U.S. Bank 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 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†	Credit Agreement, dated as of April 25, 2018, 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, 2018, 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**†	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.)
10.11**†	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.)
10.11.1**†	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.)
10.12**†	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 9, 2022

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 9, 2022
/s/ PATRICK L. BRIDGES Patrick L. Bridges	Senior Vice President/Chief Financial Officer (principal financial officer)	March 9, 2022
/s/ DENNIS J. HRUBY Dennis J. Hruby	Senior Manager Controller (principal accounting officer)	March 9, 2022
/s/ TIMOTHY A. RABON Timothy A. Rabon	Chairman, President and Director	March 9, 2022
/s/ DONALD KEAIRNS Donald Keairns	Director	March 9, 2022
/s/ JULIE KILTY Julie Kilty	Director	March 9, 2022
/s/ STUART MORGAN Stuart Morgan	Director	March 9, 2022
/s/ MATT M. BROWN Matt M. Brown	Director	March 9, 2022
/s/ SCOTT WOLFE Scott Wolfe	Director	March 9, 2022
/s/ ARTHUR W. CONNELL Arthur W. Connell	Director	March 9, 2022
/s/ THAINE MICHIE Thaine Michie	Director	March 9, 2022
/s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	March 9, 2022
/s/ CHARLES ABEL II Charles Abel	Director	March 9, 2022
/s/ LEROY ANAYA Leroy Anaya	Director	March 9, 2022
/s/ ROBERT BACA Robert Baca	Director	March 9, 2022

/s/ LUCAS BEAR Lucas Bear	Director	March 9, 2022
/s/ ROBERT BLEDSOE Robert Bledsoe	Director	March 9, 2022
/s/ LAWRENCE BRASE Lawrence Brase	Director	March 9, 2022
/s/ LEO BREKEL Leo Brekel	Director	March 9, 2022
/s/ WILLIAM BRIDGES William Bridges	Director	March 9, 2022
/s/ JERRY BURNETT Jerry Burnett	Director	March 9, 2022
/s/ KEVIN COONEY Kevin Cooney	Director	March 9, 2022
/s/ MARK DAILY Mark Daily	Director	March 9, 2022
/s/ RAYMOND BRUCE DURAN Raymond Bruce Duran	Director	March 9, 2022
/s/ JERRY FETTERMAN Jerry Fetterman	Director	March 9, 2022
/s/ JOHN FINNERTY John Finnerty	Director	March 9, 2022
/s/ JOEL GILBERT Joel Gilbert	Director	March 9, 2022
/s/ RICK GORDON Rick Gordon	Director	March 9, 2022
/s/ RANDOLPH GRAFF Randolph Graff	Director	March 9, 2022
/s/ RONALD HILKEY Ronald Hilkey	Director	March 9, 2022
/s/ RALPH HILYARD Ralph Hilyard	Director	March 9, 2022
/s/ HAL KEELER Hal Keeler	Director	March 9, 2022
/s/ BRIAN MCCORMICK Brian McCormick	Director	March 9, 2022
/s/ KOHLER MCINNIS Kohler McInnis	Director	March 9, 2022
/s/ STANLEY PROPP Stanley Propp	Director	March 9, 2022
/s/ STEVE M. RENDON Steve M. Rendon	Director	March 9, 2022

/s/ CLAUDIO ROMERO Claudio Romero	Director	March 9, 2022
/s/ PEGGY A. RUBLE Peggy A. Ruble	Director	March 9, 2022
/s/ ROGER SCHENK Roger Schenk	Director	March 9, 2022
/s/ GARY SHAW Gary Shaw	Director	March 9, 2022
/s/ DARRYL SULLIVAN Darryl Sullivan	Director	March 9, 2022
/s/ CLAY THOMPSON Clay Thompson	Director	March 9, 2022
/s/ CARL TRICK II Carl Trick II	Director	March 9, 2022
/s/ WILLIAM WILSON William Wilson	Director	March 9, 2022
/s/ PHILLIP ZOCHOL Phillip Zochol	Director	March 9, 2022