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, 2020
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
KCEC	Kit Carson Electric Cooperative, Inc.
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 Wells Fargo Bank, National Association, as 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
NMPRC	New Mexico Public Regulation Commission
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
TCP	Thermo Cogeneration Partnership, L.P., a subsidiary of ours
TEP	Tucson Electric Power Company
Trapper Mining	Trapper Mining, Inc.
Tri-State, We, Our, Us, the Association	Tri-State Generation and Transmission Association, Inc.
United Power	United Power, Inc.
Utility Members	our electric distribution member systems, consisting of both Class A members and Class B members
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 Utility Members serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We currently have 42 Utility Members after the withdrawal of DMEA in June 2020 from membership in us.

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 606,810 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 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 a 206 proceeding to determine the justness and reasonableness of our rates. Separate settlement proceedings related to our Utility Member rates and transmission service rates are on-going. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

In 2020, we also filed our "Make-Whole" 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 206 proceeding to determine the justness and reasonableness of such tariff filings. A consolidated settlement proceeding related to these three tariff filings is on-going.

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.
- 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 have tolling arrangements or long-term purchase contracts with respect to, various generating facilities. As of December 31, 2020, our diverse generation portfolio provides us with maximum available power of 4,070 MWs and is summarized in the table below:

Generation Portfolio (as of December 31, 2020)	Capacity (MW)	Percentage (%)
Coal-fired base load facilities	1,532	38
Renewables-contracts, including WAPA	1,062	26
Gas/oil-fired facilities	903	22
Other contracts, including Basin	573	14

In early 2019, we announced the execution of a 100 MW solar-based power purchase contract and a 104 MW wind-based power purchase contract. In January 2020, we announced the execution of another 200 MW wind-based power purchase contract and five solar-based power purchase contracts totaling 635 MWs. In January 2020, we also announced the early retirements of Craig Station by 2030 and Escalante Station by the end of 2020. In December 2020, we submitted to the COPUC and WAPA our 2020 Electric Resource Plan that included as part of our preferred scenario the addition of 1,850 MWs of additional renewable resources through 2030. 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, 2025, we anticipate our generation portfolio to be the following:

Generation Portfolio (as of December 31, 2025)	Capacity (MW)	Percentage (%)
Coal-fired base load facilities	1,430	28
Renewables-contracts, including WAPA	2,293	44
Gas/oil-fired facilities	903	17
Other contracts, including Basin	573	11

In addition to our diverse generation portfolio, as permitted by our wholesale electric service contracts with our Utility Members, as of December 31, 2020, 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 5,771 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 416 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.

Based upon a recent 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 2019 (which is the most recent information available to us), was below both our industry average 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, 2020, we employed 1,304 people, of which 246 were subject to collective bargaining agreements. As of December 31, 2020, the collective bargaining agreements for our operations and maintenance electrical workers and clerical electrical workers on the Western Slope of Colorado with 246 employees represented will expire in April 2021 and we are actively working on renewing such agreements. Since 2016, our number of employees has decreased by approximately 18 percent primarily due to the closure of certain facilities. 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 their locations 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. Our Non-Utility Members are as follows: 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 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.

At the April 2019 annual meeting of our Members, our Members approved amendments to our Bylaws to allow our Board to establish one or more classes of membership in addition to the then existing 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 July 2019, our Board, in accordance with the amended Bylaws, established a non-utility membership class and authorized entering into membership agreements with Non-Utility Members. The non-utility membership class, 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. The non-utility membership class is intended to consist of entities that buy from or sell to us commodities, products, services, or otherwise transact with us in a manner that provides a benefit to us and our Members. We currently have three Non-Utility Members. We may add new members in the future.

In March 2020, our Board, upon recommendation of the contract committee discussed below, 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 — Contract Committee" and "— MEMBERS — Wholesale Electric Service Contracts (Partial Requirements) - Class B members" for additional discussion regarding partial requirements.

In December 2020, at a special meeting of our Members, our Members approved certain amendments to our Bylaws and Articles of Incorporation that added certain clarifications due to the different classes of membership. In addition, 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 — Contract Committee" and "— 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 electric power to our Utility Members pursuant to long-term wholesale electric service 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, 2020, 20 Utility Members have enrolled in this program with capacity totaling approximately 131 MWs of which 126 MWs are in operation. In 2020, we estimate that nearly a third of the energy delivered by us and our Utility Members to our Utility Members' customers came from non-carbon emitting resources. See "— MEMBERS – Contract Committee" for a description of our community solar program for our Utility Members. 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, which is 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 below table shows our Utility Members' aggregate coincident peak demand for the years 2016 through 2020 and the amount of energy that we supplied them. Our Utility Members' peak demand and our annual amount of energy sold to our Utility Members for 2020 decreased by 4.3 percent and 3.2 percent, respectively, compared to 2019.

Year	Utility Members' Peak Demand (MW) (1)	Amount of Energy Sold (MWh) (1)
2020	2,880	15,884,777
2019	3,009	16,412,525
2018	2,974	16,384,415
2017	2,850	15,905,656
2016	2,802	15,746,382

(1) Includes peak demand of and energy sales to DMEA through June 30, 2020 and KCEC through June 30, 2016.

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 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 18.0 percent of our Utility Member revenue and 15.9 percent of our operating revenue in 2020. No other Utility Member exceeded 10 percent of our Utility Member revenue or our operating revenue in 2020. 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.

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 Utility Members did not supersede PURPA and the requirement of our Utility Members to purchase power from qualifying facilities. In February 2016, we filed a Petition for Declaratory Order with FERC for a clarification that the fixed cost recovery mechanism in our Board Policy 101 is consistent with the provisions of PURPA. In June 2016, FERC denied our Petition for Declaratory Order related to the fixed cost recovery mechanism in our Board Policy 101. We filed a Request for Rehearing with FERC regarding FERC's June 2016 order. In March 2020, FERC issued an order dismissing our rehearing request and vacating FERC's June 2016 order. FERC's order cited our status as FERC jurisdictional as the reasoning for vacating its June 2016 order and clarified it is as if FERC never rendered an opinion on our 2016 Petition for Declaratory Order. In July 2020, we filed a further revised Board Policy 101 that set 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. FERC accepted the revised Board Policy 101, subject to refund. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

In July 2016, on behalf of ourselves and thirty of our Utility Members, we filed a petition for a partial waiver for FERC's PURPA regulations. Pursuant to such petition, 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. FERC approved this petition for waiver in March 2020.

Contract Committee

The wholesale electric service contracts we have with our Utility Members provides 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. In 2019, the contract committee consisting of a representative from each Utility Member convened to review the wholesale electric service contracts and discuss changes, including alternative contracts with our Utility Members. The 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 make-whole number for Utility Members to withdraw from us. The contract committee consisting of a representative from each Utility Member recommend to the Board a community solar program, a partial requirements structure, including a buy-down payment methodology, and a "Make-Whole" methodology for a contract termination payment, all as further described below.

In November 2019, the contract committee recommended to the Board and the Board approved a community solar program, which 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. In October 2020, we entered into our first community solar contract with a Utility Member and filed such contract and the applicable Board policy with FERC. In December 2020, FERC accepted the community solar contract and applicable Board policy, subject to refund. FERC referred it to FERC's hearing and settlement judge procedures and consolidated it with our ongoing settlement and hearing procedures in effect for our Utility Member's rates docket.

In March 2020, based upon the recommendation of the contract committee, our Board 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 and 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. In addition, Utility Members that choose the partial requirements option will make other Utility Members financially whole through a buy-down payment. In April 2020, based upon the recommendation of the contract committee, our Board approved the terms and conditions for a buy-down payment methodology for a Class A member to become a Class B member that will make other Utility Members financially whole. In July 2020, we filed with FERC the Board approved buy-down payment methodology. In September 2020, FERC accepted our buy-down payment methodology, subject to refund, and referred it to FERC's hearing and settlement judge procedures. FERC's hearing and settlement judge procedures were also 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 is being held in abeyance pending resolution of the Jurisdictional PDO appeal. See "— MEMBERS — Wholesale Electric Service Contracts (Partial Requirements) - Class B members" for additional discussion regarding partial requirements and the open season.

In April 2020, based upon the recommendation of the contract committee, our Board approved a "Make-Whole" methodology for 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. Any termination of a Utility Member wholesale electric service contract shall continue to require Board approval. In April 2020, we filed with FERC the Board approved contract termination payment methodology. In June 2020, FERC accepted our contract termination payment methodology, subject to refund, and referred it to FERC's hearing and settlement judge procedures. Two of our Utility Members filed requests for rehearing. FERC subsequently issued an order denying the two Utility Members requests for rehearing. 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 is being held in abeyance pending resolution of the Jurisdictional PDO appeal.

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

In October 2020, our Board approved the partial requirements contract form and associated partial requirements policies and started the implementation process by providing a ninety-day notice prior to the start of the open season. In November 2020, we filed with FERC the applicable Board approved partial requirements policy related to the open season. In January 2020, FERC accepted our partial requirements policy related to the open season, subject to refund, and referred it to FERC's hearing and settlement judge procedures. FERC's hearing and settlement judge procedures were consolidated with FERC's hearing and settlement judge procedures for our contract termination payment methodology discussed above. FERC also ordered that the policy, including the issuance of the ninety-day notice period, cannot go into effect until January 10, 2021. As a result, we reissued the ninety-day notice on February 8, 2021, which began the ninety-day notice period. The open season will start on May 10, 2021.

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, based upon the recommendation of the contract committee, our Board approved a "Make-Whole" methodology associated with termination of a Utility Member's wholesale electric service contract with the intent of developing a standardized exit charge or contract termination payment methodology that will permit an orderly and equitable process. The April 2020 Board approval also provides that the withdrawal process requires advance notice of the proposed date of withdrawal, Board approval, and a determination by our Board that the proposed withdrawal will not have a material adverse effect on us. In April 2020, we filed with FERC the Board approved contract termination payment methodology. See "— MEMBERS – Contract Committee." In late 2020, certain Utility Members formally requested a contract termination payment amount for planning purposes, but have not provided a notice of intent to withdraw. In January 2021, we notified each of these Utility Members that the contract termination payment calculation is time-intensive and complex and that we are working on a contract termination procedure to be filed with FERC. In late February 2021, seven of our Utility Members filed a complaint with FERC seeking the contract termination payment amount on an expedited basis. In March 2021, our Board approved a contract termination procedures Board policy that requires a Utility Member to provide a deposit and to pay the actual costs of preparing the contract termination calculation, subject to an aggregate cap. The Board policy also provides that we will begin accepting requests for contract termination calculations 60 days after FERC accepts this Board policy, the calculation is valid for 180 days after receipt by the Utility Member, and the Utility Member must provide three years advance notice of withdrawal. In addition, the Board policy sets forth various factors our Board will consider in determining if a proposed withdrawal will have a material adverse effect on us. We plan to file this Board policy with FERC.

From time to time, a Utility Member may request equitable terms and conditions as our Board may prescribe for withdrawal, or we may provide for informational purposes, to all or a portion of our Utility Members equitable terms and conditions for withdrawal. In addition, from time to time, we may be in discussions with a Utility Member regarding the equitable terms and conditions for withdrawal and their request for withdrawal, including granting a Utility Member permission to explore options for potential alternative supplies of power, known as shopping letters. However, any such permission is not considered authorization to withdraw and does not change the Utility Member's requirements and obligation to comply with such equitable terms and conditions as our Board may prescribe. A Non-Utility Member's ability to withdraw from membership in us is as provided in their respective membership agreement.

In July 2019, we reached a settlement with DMEA that provided for their withdrawal from membership in us as permitted by our Bylaws, the resolution of all litigation with DMEA regarding various matters, the transfer of certain transmission assets to DMEA, the forfeiture by DMEA of the current balance of DMEA's patronage capital allocation, and the payment to us of a withdrawal payment. The specific terms of the settlement were set forth in a withdrawal agreement. In April 2020, we entered into the membership withdrawal agreement and an associated purchase and sales agreement with DMEA for the sale of certain assets and facilities to DMEA. On June 30, 2020, DMEA withdrew from membership in us pursuant to the membership withdrawal agreement. The membership withdrawal agreement provided for the payment to us by DMEA of $88.5 million, the assignment by us of the wholesale electric service contract between us and DMEA to DMEA's new third-party power supplier, the withdrawal of DMEA from membership in us, the retirement by us and forfeiture by DMEA of $47.7 million of DMEA's patronage capital allocation, and the conveyance of certain assets and facilities by us to DMEA. The $88.5 million in cash, included the $26 million for the conveyance of certain assets and facilities by us to DMEA.

In November 2019, LPEA filed a formal complaint with the COPUC alleging that we hindered LPEA's ability to seek withdrawal from us. In November 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. The COPUC consolidated the proceeding. In July 2020, the administrative law judge issued a recommended decision, but the COPUC on its own motion stayed the recommended decision. In October 2020, the COPUC determined that COPUC's jurisdiction over United Power and LPEA's complaints was preempted by FERC and dismissed both complaints without prejudice. In January 2021, United Power appealed COPUC's decision to the Denver County District Court. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

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 a "Make-Whole" methodology for 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 June 2020, we filed our answer denying United Power's allegations and request for relief. We asserted counterclaims against United Power, and requested declaratory judgements on certain matters. In June 2020, the three Non-Utility Members filed a joint motion to dismiss. In December 2020, the complaint against our three Non-Utility Members was dismissed. In addition, in November 2020, United Power filed a complaint for declaratory relief against us seeking the court to declare that our addition of the Non-Utility Members violated Colorado law. In December 2020, United Power sought to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add the claims from its November 2020 complaint into its amended complaint and to dismiss the November 2020 complaint against us. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

Responsible Energy Plan

In July 2019, we announced that we are pursuing a Responsible Energy Plan to transition to a cleaner generation portfolio while ensuring reliability, increasing Utility Member flexibility, all with a goal to lower wholesale rates to our Utility Members. A key part of our approach was an engagement with former Colorado Governor Bill Ritter and the Center for the New Energy Economy at the Colorado State University to facilitate a collaborative stakeholder process for us that contributed to and helped define the Responsible Energy Plan.

Our Responsible Energy Plan will rapidly advance our transition to a cleaner generation portfolio and offer new programs to serve our Utility Members. 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 year, 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 2020 progress highlights are below:

- Reduce emissions – Retirement of Escalante Station by the end of 2020 and Craig Station by 2030. By 2030, in Colorado, we are targeting a 100 percent reduction in CO_2 emissions from coal generation, 90 percent reduction in CO_2 emissions across generation we own or operate, and 80 percent reduction in CO_2 emissions associated with wholesale electric sales relative to 2005 levels.
    - *2020 progress*: Our Escalante Station in New Mexico came offline in August 2020, we determined the retirement date for Craig Station Unit 2 to be by September 30, 2028, and our Board approved increasing our goal for CO_2 emissions reductions associated with wholesale electric sales in Colorado from 70 percent by 2030 to 80 percent.

- 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 members system-wide will be clean energy.
    - *2020 Progress*: We set the above referenced goal of 70 percent clean energy system-wide by 2030 and as part of our 2020 Electric Resource Plan preferred scenario, we identified an additional 1,850 MWs of renewables and 200 MWs of energy storage to increase our clean energy to roughly 4,000 MWs by 2030.

- Extending clean grid benefits – Committing to 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.
    - *2020 Progress*: We committed nearly $2 million to extend the public electric vehicle (EV) charging network across our Utility Members' service areas and expanded programs to help consumers save money and energy while cutting emissions.

- Increase member flexibility – Working together with our Utility Members to develop a more flexible contract structure so they can self-supply more power than ever before.
    - *2020 Progress*: Our Board approved and FERC accepted a flexible partial requirements membership option that would permit Utility Members collectively to self-supply up to 300 MWs and FERC accepted our community solar Board policy.

- 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.
    - *2020 Progress*: We made a $5 million donation to support community development in the Escalante Station area and donated an additional $500,000 in Montrose County, CO to support economic and community development following the 2019 retirement of Nucla Generating Station. In addition, we supported Escalante Station employees with severance packages, assistance with education and financial planning, and supplemental funding for health benefits.

- 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.
    - *2020 Progress*: We clarified that FERC is the exclusive, independent regulator of our rates and contract termination payments, set a goal of reducing our Utility Members rates by eight percent by the end of 2023, and

submitted a letter of intent to SPP to evaluate participation in SPP's regional transmission organization in the Western Interconnection.

Utility Members' Service Territories and Customers

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.

Customers. According to information we received from our Utility Members, our Utility Members' sales of energy in 2019 (which is the most recent information available to us) were divided by customer class as follows:

Customer Class	Percentage of MWh Sales	Percentage of Customers
Residential	30.0 %	83.0 %
Large commercial	37.6	0.1
Small commercial	23.3	12.8
Irrigation	6.6	3.8
Other	2.5	0.3

From 2015 to 2019, our Utility Members experienced an average annual compound growth rate of approximately 1.7 percent in the number of customers and an average annual compound growth rate of approximately 2.0 percent in energy sales. In 2019 (which is the most recent year with data available to us), the 15 largest customers of our Utility Members represented 20.0 percent of the aggregate retail electric energy sales by our Utility Members, although no single customer of our Utility Members represented more than 4 percent of our total energy sales. These customers are primarily in the business of mineral extraction, natural gas, CO_2, oil production, or transportation of these.

Our Utility Members' average number of customers per mile of energized line is approximately five customers per mile. System densities of our Utility Members in 2019 ranged from 1.3 customers per mile to 15.1 customers per mile.

The information contained above was taken from Rural Utilities Service Financial and Statistical Reports (Form 7) or similar reports prepared for other lenders or provided directly by our Utility Members. All this information was prepared by our Utility Members and has not been independently verified by us. Certain Utility Members did not provide us updated information for 2019 and we used information previously provided by such Utility Member.

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 3.6 percent of our total load and transmission facilities are 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 number payable 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

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.

In December 2019, we filed a set of tariff filings, including our stated rate cost of service filing, our wholesale electric service contracts, our Bylaws, certain Board policies, market based rate authorization, and transmission OATT. In addition, in December 2019, we filed our Jurisdictional PDO with FERC asking FERC to confirm our jurisdiction under the FPA. In March 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 a 206 proceeding 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 judge to encourage settlement of material issues and to hold a hearing if settlement is not reached. The settlement proceedings are continuing and settlement offers are being exchanged under the FERC administrative law judge's guidance and in participation with FERC staff. A fourth settlement conference occurred in December 2020 and a technical conference occurred on January 21, 2021. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

Rate Regulation

The electric power we provide to our Utility Members are at rates established by our Board, but such rates are subject to FERC's approval. Our wholesale electric service contracts with our Utility Members provide that rates paid by our Utility Members for the electric power 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 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.

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

As approved by our Board in October 2020, the A-40 rate schedule will continue in effect for 2021, subject to the 206 proceeding discussed above. The average budgeted Utility Member cents/kWh for 2021 will remain the same as 2020. Our Board also set a goal of reducing our Utility Members rates by eight percent by the end of 2023.

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 2016 through 2020. 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 2016 through 2020.

Year	Average Utility Member Revenue (Cents/kWh)
2020	7.531
2019	7.547
2018	7.543
2017	7.544
2016	7.207

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, contract for, lease, have undivided percentage interests in or have tolling arrangements with, and through the purchase of electric power pursuant to power purchase contracts and purchases on the open market.

In 2020, 58.2 percent of our energy available for sale was provided by our generation and 41.8 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. In 2020, we estimate that nearly a third of the energy delivered by us and our Utility Members to our Utility Member's customers came from non-carbon emitting resources. We estimate that 50 percent of the energy delivered by us and our Utility Members to our Utility Member's customers will come from clean energy by 2024.

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 1,532 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.

In August 2020, electricity production ended at our 253 MW Escalante Station and, in December 2020, it was officially retired from service. We announced the planned retirement in January 2020 as part of our Responsible Energy Plan.

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 218 employees.

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.

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 2020 was approximately 335 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.

Renewables. Our principal long-term renewable power purchase contracts are 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 amount of long-term power delivery from WAPA under the two contracts that begin delivery of power on October 1, 2024 is anticipated to remain near the current amount under the existing three contracts terminating on September 30, 2024. 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

In addition to our contracts with WAPA for hydroelectric power purchases, 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. 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 these 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	2023	(1)	2038	(2)
Crossing Trails Wind	Colorado	Crossing Trails Wind Power Project, LLC	Wind	104	2021	(1)	2036	(2)
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	(1)	2041	(2)
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.

Other. In 2016, we entered into a five year reciprocal contract 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. After the initial five year period, the contract automatically renews for successive one year terms until terminated by either party. 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. 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

In September 2019, we announced, together with Basin, WAPA Rocky Mountain Region, WAPA Upper Great Plains West, and WAPA Colorado River Storage Projects, our decision to join SPP's Western Energy Imbalance Service market. Since then Municipal Energy Association of Nebraska, Wyoming Municipal Power Agency, and Deseret Power Electric Cooperative have also joined. SPP launched the Western Energy Imbalance Service market on February 1, 2021with eight utilities participating. 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 April 2021, PNM plans to join as an EIM entity in the CAISO Western Energy Imbalance Market. This will affect our loads and resources within the PNM balancing authority, which is all our loads and resources in New Mexico. We have registered as a CAISO 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.

In addition, we continue to explore options to participate in a regional transmission organization in the Western Interconnection. In November 2020, we, together with Basin, WAPA, Municipal Energy Agency of Nebraska, and Deseret Power Electric Cooperative, submitted letters to SPP to evaluate participation in 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 an organized market in the Western Interconnection, and the regulatory requirements for meeting 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.

The Colorado General Assembly in 2019 passed legislation that revises processes undertaken by the COPUC. Among other provisions, the bill requires us to file and obtain COPUC approval for our electric resource plans and directs that such plans consider the cost of CO_2 emissions associated with our generating facilities. On July 31, 2019, the COPUC opened a rulemaking pursuant to the bill proposing electric resource planning rules applicable to us. In April 2020, the COPUC finalized these rules which now require a Phase I/Phase II process that is similar to the electric resource planning process that currently applies to Colorado's investor owned utilities. Our first electric resource plan under the new rules, which is Phase I, was filed with the COPUC on December 1, 2020. Our preferred scenario in our resource plan will reduce greenhouse gas associated with our wholesale electricity sales in Colorado by 80 percent by 2030, when compared to a 2005 baseline. Our preferred scenario also includes 1,850 MWs of additional renewable generation, more than 200 MWs of energy storage, and the retirement of our remaining Colorado coal units by the end of 2030. The COPUC will consider and act on the filing, and that process will continue in 2021. We anticipate that our initial Phase II process will focus on our resource needs by 2025, which based upon our preferred scenario is another 200 MWs of wind-based renewable resources.

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(1)	Colowyo Mine	2027	800,000
Craig Station Unit 3	Colowyo Mine	2027	1,300,000
Laramie River Generating Station	Various, including Dry Fork Mine	2041	1,900,000
Springerville Unit 3	North Antelope Rochelle Mine	2021	1,250,000 to 1,500 ,000

(1) Our contract for coal from Trapper Mine expired at the end of 2020 and we withdrew from membership in Trapper Mining.

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 October 2018, Colowyo Coal received a renewal of a water/wastewater discharge permit, which now also includes the Collom pit. 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. During all or part of 2020, we provided guarantees of, or self-bonds for, certain reclamation obligations of WFW and our subsidiaries. We no longer provide guarantees of, or self-bonds for, any reclamation obligations. 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. We no longer have any reclamation liabilities associated with Trapper Mine, Dry Fork Mine or Fort Union Mine.

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 be available in the foreseeable future. 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. 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 water supplies or to curtail generation at our facilities.

TRANSMISSION

We have ownership or capacity interests in approximately 5,771 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 416 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 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. The settlement proceedings are continuing and settlement offers are being exchanged under the FERC administrative law judge's guidance and in participation with FERC staff. See Note 15 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. On October 30, 2015, SPP filed revisions to its OATT to add an annual transmission revenue requirement and to implement a formula rate template and implementation protocols for those Eastern Interconnection transmission facilities on behalf of us for transmission service beginning January 1, 2016. NPPD filed motions protesting the October 2015 filing. In December 2015, FERC issued an order accepting the formula rate subject to refund and setting it for settlement and hearing judge procedures. The settlement and hearing commenced in 2016 and involved two parts. The first part being the formula rate determinations, which was settled, and the second part being SPP's zonal placement of our transmission facilities that are located in the Eastern Interconnection, which could not be settled and a hearing took place in November 2016. In February 2017, the Administrative Law Judge issued an initial decision recommending that FERC approve SPP's zonal placement of our transmission facilities on the zonal placement part. In May 2018, FERC affirmed the initial decision and no refund was owed by us on this part of the matter. In March 2019, NPPD filed a petition for review at the United States Court of Appeals for the Eighth Circuit. In April 2020, the United States Court of Appeals for the Eighth Circuit denied NPPD's petition for review.

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 eight regional entities. We are registered in two of the eight 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. We are scheduled for a compliance audit in 2021 as part of a three-year routine audit cycle.

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 $12.5 million through 2025 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 nineteen 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 Legislation

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.

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, hampers reliability or increases 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 2021 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 come from renewable sources in 2021.

The impacts of the 2019 Colorado and New Mexico legislation 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.

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. On October 23, 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.

On February 9, 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 (ACE) rule. The ACE 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 ACE rule, and on January 19, 2021, the D.C. Circuit Court of Appeals issued an opinion vacating both the ACE rule and the repeal of the Clean Power Plan. Petitions to rehear this determination are expected. If re-hearing is denied, petitions are expected to be filed to the United States Supreme Court to reverse the D.C. Circuit Court of Appeals decision. The Biden administration is expected to begin another, new rulemaking.

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 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. 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 2021. Implementation of an ozone standard of 70 ppb will require the evaluation of additional emission controls for all 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. On June 15, 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 are due in July 2021 for the second 10-year period. 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.

On March 6, 2017, the EPA and the Corps published in the Federal Register a notice that it intended to revise and rescind or revise the 2015 expansion of regulatory authority under the Clean Water Act through broadening the definition of WOTUS and identified a two-step process regarding the definition of WOTUS. Step one was a proposal to withdraw the 2015 definition of WOTUS, which was finalized in September 2019. Step two is a new WOTUS definition, titled the Navigable Waters Protection Rule, which the EPA and the Corps promulgated on April 21, 2020. The new Biden administration may review and reconsider the Navigable Waters Protection Rule.

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 initial 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. On January 20, 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. On November 7, 2019, the Collom air permit revision for the Collom pit at the Colowyo Mine was issued by CDPHE. On December 11, 2019, the Center for Biological Diversity and Sierra Club filed a new case challenging the CDPHE's issuance of the Collom air permit revision. On October 21, 2020, the judge issued an order affirming the CDPHE's issuance of the minor source construction air permit to Collom. On December 8, 2020, the Center for Biological Diversity and Sierra Club filed a notice of intent to appeal the decision in this case.

Mine Reclamation. The EPA is working with the OSMRE and state mine reclamation regulators to develop a better understanding of mine placement practices for coal ash. The OSMRE may issue a proposed rulemaking establishing requirements and standards that apply when coal ash is used during reclamation at surface coal mining operations. However, recent regulatory agendas indicate that OSMRE is not actively pursuing these plans. Until these rules might be promulgated, we cannot determine what, if any, controls we may be required to implement to comply with the regulation.

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 U.S. Fish and Wildlife Service 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 U.S. Fish and Wildlife Service manages future species listings via a 5-year National Listing Workplan, which was recently updated in January 2021. We monitor the workplan for upcoming species listings that might affect our operations and plans. In particular, we will pay attention to several species with workplan timing estimates in the next few years such as: lesser prairie chicken, three bat species, plains spotted skunk, western bumble bee and monarch butterfly. It is difficult to predict if and how these potential future species listings might affect our operations because U.S. Fish and Wildlife Service may decline to list these species or may list species that reduce or eliminate activity restrictions. Separate from species listings, the U.S. Fish and Wildlife Service finalized multiple Endangered Species Act regulatory changes in the past several years that are expected to improve Endangered Species Act implementation. The new Biden administration may review and might reconsider these final rules, as well as the recent decision to delay listing the monarch butterfly.

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 may materially impact our financial condition, results of operations 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 June 2020, FERC accepted our Board approved contract termination payment methodology 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 and referred it to FERC's hearing and settlement judge procedures. The Board approved withdrawal process also requires advance notice of the proposed date of withdrawal, Board approval, and a determination by our Board that the proposed withdrawal will not have a material adverse effect on us. See "BUSINESS — MEMBERS – Contract Committee." FERC also determined it had exclusive jurisdiction over our contract termination payments. United Power has filed various legal actions challenging our addition of our Non-Utility Members, FERC's jurisdiction over us, and the contract termination payment methodology. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

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 our Board may proscribe, it may materially impact us. In addition, if we underestimate the monetary value of a Utility Member's obligation or a significant number of our Utility Members withdraw, it may materially impact us.

The material impacts could include increased rates to our Utility Members, a materially adverse effect on our financial condition and results of operations, and we may be required to offer a prepayment of certain of our long-term debt, without paying a make-whole amount. 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 our other 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.

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. The price for wholesale electricity has decreased substantially in the past five years driven by continued sustained low natural gas prices, decreasing prices for renewable energy, competing third party energy remarketing companies, and new and more efficient technology. Lower wholesale electricity prices have resulted in increased pressure from our Member Utilities to lower our Utility Members wholesale rates and resulted in increased Utility Member unrest and desires by our Utility Members to withdraw. Continued wholesale electricity prices that are lower than our wholesale rates to our Utility Members could result in increased pressure from our Utility Member to make our Utility Member wholesale rates more competitive and result in continued and additional Utility Member unrest.

In 2020, our Board set a goal of reducing our Utility Members rates by eight percent by the end of 2023. Although we believe that this goal 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 achieve such reduction in wholesale rates. If our Utility Members do not believe that we have adequately addressed their concerns through our rate reduction goal or we are not able to achieve such goal, we may experience continued and additional Utility Member unrest and desires to withdraw, unfavorable media coverage, additional laws and regulations targeted at us, or other negative consequences which may impact our financial condition or future plans.

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's approval or acceptance. Our existing Class A wholesale rate structure (A-40) to our Utility Members was accepted at FERC as a "stated rate," subject to refund. FERC did not determine that our Utility Member rates were just and reasonable and ordered a 206 proceeding to determine the justness and reasonableness of our Utility Members' rates and wholesale electric service contracts. The 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. See Note 15 to the Consolidated Financial Statements in Item 8 for further information. In addition, upon our next rate change, we will be required to justify the new rates to our Utility Members at FERC with a rate case, likely to be contested.

Challenges to the rates approved by our Board and filed with FERC for approval 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, it 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.

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.

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 the states, 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.

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 number payable 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. 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 2019 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 20.0 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. Additional or continued outages at facilities of these customers due to COVID-19 or other reasons could continue to reduce demand from and energy sales to our Utility Members. A continued or increased downturn in the economy or sustained low 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 announced the actions of our Responsible Energy Plan whereby we outlined our intention to early retire certain of our coal-fired generating facilities, reduce emissions and increase our renewable portfolio, increase Utility Member flexibility to develop more, self-supplied renewable energy, and provide community support for transitioning communities. 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 not identified herein will be receptive to our Responsible Energy Plan or believe that our Responsible Energy Plan addresses their concerns. 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. As part of the resource planning proceeding for our 2020 Electric Resource Plan filed with the COPUC that include our scheduled early retirements of coal-fired generating facilities, the schedule for retirement of our resources will be evaluated. If our Utility Members, environmentalists, legislatures, regulatory agencies, lenders, local communities, or other stakeholders do not accept our Responsible Energy Plan or our 2020 Electric Resource Plan filed with the COPUC, or believe that we have 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 current Utility Members' wholesale rates and our transmission rates may be determined by FERC to not be just and reasonable and we may be subject to certain refunds.

Our existing Class A wholesale rate structure (A-40) to our Utility Members was accepted at FERC as a "stated rate," subject to refund. FERC did not determine that our Utility Member rates were just and reasonable and ordered a 206 proceeding to determine the justness and reasonableness of our Utility Members' rates and wholesale electric service contracts. The 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. We may be required to accrue certain liabilities associated with the amounts subject to refund and may be required to refund certain revenue collected. Furthermore, current practices including our use of regulatory assets may be subject to change as a result.

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 2020, 92.3 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.

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 would 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. The plaintiffs in these actions have also claimed that we owe them independent duties regarding our Utility Members. We strongly dispute these claims as inconsistent with the facts and law. 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, the jury determined we violated an independent duty owed to the plaintiffs and were 20 percent at fault as a result of the Utility Member's independent actions. 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 Risk

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 use and the 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 with a change in the federal administration 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 2020, our existing generating facilities generated approximately 58.2 percent of our energy available for sale, a substantial percentage of which is generated by coal-fired generating facilities. The cost impact of the implementation of regulation 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.

Operating Risks

Continued sustained low 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. Continued sustained 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, and 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.

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.

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

Our performance depends on the successful operation of our electric generating facilities. Operating generating 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;

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

We 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, labor relations, communicable diseases, permitting, regulatory matters, and 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 from time to time 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. Similar inventory shortages could 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 and similar 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 would have an adverse effect on our results of operations.

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, could have a material adverse effect on our results of operations, financial condition and cash flow. The COVID-19 pandemic has adversely impacted economic activity and conditions worldwide. Measures to control the spread of COVID-19 have affected the demand for the products and services of many businesses in our Utility Members' service territories. There remains considerable uncertainty regarding the extent to which COVID-19 will continue to spread and how long until herd immunity will occur through vaccinations or otherwise. In addition, there is uncertainty regarding the extent and duration of measures to try to contain the virus such as phased re-opening of certain businesses, including re-opening at limited capacity. 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, including the availability and adoption rate of the COVID-19 vaccines, the scope and timing of actions to further contain the virus or treat its impact, and to what extent normal economic and operating conditions can resume, among others. We continue to monitor the impacts of the pandemic on our workforce, liquidity, capital markets, reliability, cybersecurity, customers, suppliers, and macroeconomic conditions and cannot predict whether COVID-19 will have a long-term material impact on our business. However, a protracted slowdown of broad sectors of the economy, changes in demand for commodities, particularly oil and gas, or significant changes in legislation or regulatory policy to address the COVID-19 pandemic or any other widespread outbreak of a communicable disease could result in reduced demand for electricity from our Utility Members and in our region, late payments by our Utility Members, and the inability of our contractors, suppliers and other business partners to fulfill their contractual obligations, any of which could have a material adverse effect on our results of operations, financial condition and cash flows. It is possible that actual, perceived or projected negative impacts to our business or Utility Members' businesses from the impacts of COVID-19 or any other widespread outbreak of a communicable disease could be the impetus for negative rating action by credit rating agencies.

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 expected 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 our Responsible Energy Plan that meets 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 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. In the years 2021 through 2025, we estimate that we may invest approximately $429 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;
- unanticipated increases in cost of materials and labor; and
- performance by engineering, construction or procurement contractors.

The early retirement of and decommissioning of certain of our existing generating facilities, including Craig Station, Escalante Station, and Nucla Generating 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 5,771 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 contracts 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 2020, purchased power provided 41.8 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 contracts and short-term market purchases of electric power. We also rely on long term contracts 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 contracts 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 contracts, we rely on models based on our judgments and assumptions of factors such as future demand for electric power, future market prices of electric power and the future price of commodities used to generate electricity. These judgments and assumptions may prove to be incorrect. As a result, we may be obligated to purchase electric power under long term agreements at a price which is higher than we could have obtained in alternative short term arrangements. Conversely, our reliance on short-term market purchases exposes us to increases in electric power prices.

Our long term power purchase contracts include contracts with WAPA and Basin, consisting of 14.8 percent and 15.1 percent, respectively, of our Utility Member sales in 2020. We experience favorable pricing terms under our WAPA contracts under federal laws that give preference to federal hydropower production to certain 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. The rate we pay Basin is also subject to 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 operate in a capital-intensive industry and therefore debt comprises a majority of our capital structure.

As of December 31, 2020, we had total debt outstanding of approximately $3.3 billion, of which approximately $3.0 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, 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 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.

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, 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 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 our other 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 and 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 2021 through 2025, we estimate that we may invest approximately $799 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;

- continued 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;
- 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, 2020, we had $449.6 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, 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.

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 2021. 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.

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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Generating Facilities

We own, lease, have undivided percentage interests in, or have tolling arrangements with respect to, 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	27.1	Coal	570	—	1980
Laramie River Generating Station Unit 2	Wyoming	27.1	Coal	570	232	1981
Laramie River Generating Station Unit 3	Wyoming	27.1	Coal	570	232	1982
Springerville Generating Station Unit 3	Arizona	100.0	Coal	420	420	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, 1,710 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 four other regional utilities pursuant to a participation agreement. We own a 27.1 percent interest in the total capacity of the facility. Certain costs associated with operating the facility are divided on a pro-rata basis among the participants, while other costs are shared in proportion to the generation scheduled and energy produced for each participant. Laramie River Generating Station Unit 1 is connected to the Eastern Interconnection, while Units 2 and 3 are connected to the Western Interconnection. Our share of Laramie River Generating Station's total capacity is 464 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 420 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 420 MWs of capacity from the unit and selling 100 MWs of such capacity to Salt River Project and 100 MWs of such capacity to PNM. 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. J.M. Shafer Generating Station is owned by our wholly-owned subsidiary TCP. We utilize the entire 272 MWs of output under a tolling arrangement with TCP. Our interest in J.M. Shafer Generating Station is not subject to the lien of our Master Indenture, but our interest in the tolling arrangement with TCP is subject to the lien of our Master Indenture. In December 2020, our Members approved merging the entities, including TCP, that own J.M. Shafer Generating Station into Tri-State. Upon completion of the merger, our ownership of J.M. Shafer Generating Station will be subject to the lien of our Master Indenture. We have not established a timeline for completion of the mergers.

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, 2020, 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	3,244
138	173
230	1,198
345	1,100
Total	5,771

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 416 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 large surface mine 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.

We were a member of Trapper Mining, which is the owner and operator of the Trapper Mine. In December 2020, upon termination of our coal supply agreement with Trapper Mining, we withdrew from our membership in Trapper Mining.

Dry Fork Mine is owned by WFW. WFA owns all the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 27.13 percent undivided interest) own the remaining 25 percent of class BB shares of WFW. In December 2020, we withdrew from membership in WFA and as a result ceased having any representation on the WFW board of directors.

In December 2020, we transferred our ownership in the land and rights to mine the Fort Union Mine to Basin.

ITEM 3. LEGAL PROCEEDINGS

Information required by this Item is included below and also contained in Note 15 to the Consolidated Financial Statements in Item 8.

NMPRC Proceeding. On October 19, 2012, we gave notice, as required by New Mexico law, to the NMPRC of our A-37 wholesale rate which was scheduled to become effective on January 1, 2013. The rate would have increased revenue collected from all of our Utility Members. In November 2012, three of our Utility Members located in New Mexico filed protests of our rates with the NMPRC. On December 20, 2012, the NMPRC suspended the rate filing in New Mexico. On January 25, 2013, we filed a Complaint for Declaratory and Injunctive Relief in the Federal District Court in New Mexico asking the Court to declare the actions of the NMPRC to be in violation of the Commerce Clause of the United States Constitution. On September 10, 2013, we gave notice, as required by New Mexico law, to the NMPRC of our A-38 wholesale rate which was scheduled to become effective on January 1, 2014. Four Utility Members filed protests with the NMPRC challenging the A-38 rate. The A-38 rate modified the rate design but did not increase the general revenue requirement. On December 11, 2013, the NMPRC suspended the A-38 rate filing. In August 2014, we and the New Mexico Utility Members executed a preliminary mediation agreement providing for a temporary rate rider through no later than December 31, 2015, and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. In October 2015, the Federal District Court in New Mexico temporarily stayed the federal proceeding to allow the parties' time to negotiate a global settlement. On December 30, 2020, we and the NMPRC filed a joint motion to dismiss the federal district court case. On December 9, 2015, we and the New Mexico Utility Members filed a joint motion with the NMPRC seeking continuation of the suspension of the procedural schedule related to the rate protests to allow the parties additional time to proceed with further negotiations towards a global settlement. On January 6, 2016, the NMPRC ordered that the procedural schedule related to the rate protests remains suspended until further order of the NMPRC. As part of the global settlement, the parties sought to address the issue of our rate regulation in New Mexico, payment of capital credits, and whether we have the right to collect the amounts uncollected from our New Mexico Utility Members as a result of the suspension of prior rate filings. The rate protest proceeding before the NMPRC remains open due to administrative reasons, but was rendered moot when our A-39 rate schedule went into effect on January 1, 2016.

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. SELECTED FINANCIAL DATA

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. (a non-governmental/non-electric cooperative entity), as a new Member/owner.

We supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long term purchase contracts and short term energy purchases. We own, lease, have undivided percentage interests in, have tolling arrangements or long-term purchase contracts with respect to, various generating facilities. Our diverse generation portfolio provides us with maximum available power of 4,070 MWs, of which approximately 1,062 MWs comes from renewables. In 2020, we estimate that nearly a third of the energy delivered by us and our Utility Members to our Utility Members' customers came from non-carbon emitting resources.

In 2020, we sold 17.5 million MWhs, of which 90.8 percent was to Utility Members. Total revenue from electric sales was $1.3 billion for the year ended December 31, 2020, of which 92.1 percent was from Utility Member sales. Our results for the year ended December 31, 2020 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.

- Non-member electric sales increased by $7.1 million, or 7.5 percent, primarily due to the recognition of $12.1 million of previously deferred non-member revenue as part of our Utility Member rate stabilization measures and more favorable pricing for term sales during the year.

- Fuel expense decreased $45.5 million, or 16.2 percent, primarily due to lower generation from our generating facilities, fluctuations in fuel prices, and overall decreased demand as a result of impacts from COVID-19.

- General and administrative expense increased $20.2 million, or 40.7 percent, primarily due to an increase in outside professional services, regulatory commission expenses, as well as an increase related to general and administrative labor and benefits.

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, 2020, 20 Utility Members have enrolled in this program with capacity totaling approximately 131 MWs of which 126 MWs are in operation. DMEA withdrew from membership in us in June 2020 and DMEA's contract was assigned by us to DMEA's new third-party power supplier. 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 “Make-Whole” methodology for a contract termination payment. Each of these items recommended by the contract committee representing our Utility Members were filed with FERC for approval in 2020. FERC accepted each of these items, subject to refund, and referred them to FERC's hearing and settlement judge procedures. See “BUSINESS – MEMBERS – Contract Committee.”

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 the wholesale electric service contract with United Power. In November 2020, United Power filed a complaint for declaratory relief against us seeking for the court to declare that our addition of the Non-Utility Members violated Colorado law. In December 2020, United Power sought to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add the claims from its November 2020 complaint into its amended complaint and to dismiss the November 2020 complaint against us. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

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.
- 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.”

Early Retirements of Generating Facilities

As part of our Responsible Energy Plan, in January 2020, our Board approved the early retirement of Escalante Station by the end of 2020 and Craig Station Units 2 and 3 and the Colowyo Mine by 2030. The early retirement of Craig Station Unit 1 by December 31, 2025 remains unchanged. In August 2020, electricity production ended at Escalante Station in New Mexico, and we no longer produce power from coal in New Mexico.

During 2020, in accordance with accounting requirements, we recognized an impairment loss and other closure costs of $283.0 million associated with the early retirement of Escalante Station. Our Board approved the deferral of such impairment loss as a regulatory asset. This loss will be amortized to depreciation, amortization and depletion expense beginning in 2021 through the end of 2045, which was the depreciable life of Escalante Station, and is expected to be recovered from our Utility Members through rates. Such deferral and recovery was approved by FERC during the third quarter of 2020. Craig Station Units 2 and 3 continue to be depreciated over the last rate study end lives of 2039 and 2044. Once it becomes probable that FERC will approve the impairment and recovery of unrecovered depreciation associated with the closure of Craig Station Units 2 and 3, then the expected unrecovered depreciation at the time of the closure will be impaired and recovered from our Utility Members through rates. The net book value of Craig Station Units 2 and 3 was $417.0 million as of December 31, 2020. The shortened life of Colowyo Mine increases annual depreciation, amortization and depletion expense in the amount of approximately $12.7 million.

In connection with such early retirements, our Board continues to evaluate the creation of regulatory assets and use of regulatory liabilities to ensure our Utility Member rates remain stable, if not lower, during this transition. A creation of regulatory asset to defer expenses associated with these early retirements or the utilization of regulatory liabilities would require FERC approval.

COVID-19 Impacts

The COVID-19 pandemic has adversely impacted economic activity and conditions worldwide, including workforces, liquidity, capital markets, consumer behavior, supply chains, and macroeconomic conditions.

We are intensely focused on safely delivering power to our Utility Members and ensuring the reliability of the regional power grid, protecting our employees' health, and supporting state and national directives to stem the spread of COVID-19 in our communities. We have activated established programs and procedures to mitigate the impacts of pandemics and protect our employees from communicable diseases. Our Crisis Management Team, representing all functions of our operations, continues to assess potential impacts to our operations and is taking actions that mitigate those impacts. These actions include: ensuring our critical generation, transmission and operations teams are staffed and have the resources needed to safely operate our power system; implementing best practices to protect employees from the spread of COVID-19, including achieving social distancing for employees through work from home programs; and holding our board meetings and membership meetings virtually. We have also supported COVID-19 pandemic relief and recover funds in each of the four states of our Utility Members, including donations totaling $200,000.

In each of our Utility Members states, the governor of such state or officials of certain counties and communities have implemented various and different measures related to COVID-19 in 2020, including stay-at-home orders, safer-at-home orders, mandating the closure of certain businesses, and phased re-opening of certain businesses. The various governmental measures are constantly changing.

The economic impacts of the COVID-19 pandemic and the various government measures related to COVID-19 have caused a significant slowdown in certain sectors of the economy, including oil and gas, and a corresponding increase in unemployment. We have experienced changes in the load patterns of our Utility Members and decreased sales to our Utility Members and Utility Member revenue due to disruptions of operations from our Utility Members' commercial customers. We continue to monitor the impacts of COVID-19. 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, including the availability and adoption rate of the COVID-19 vaccines, the scope and timing of actions to further contain the virus or treat its impact, and to what extent normal economic and operating conditions can resume, among others. We currently believe that we have sufficient liquidity to meet our anticipated capital and operating requirements, and we completed two long-term debt transactions in June 2020 with proceeds totaling $225 million.

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.

Leases. Prior to the adoption of Accounting Standards Update 2016-02, *Leases (Topic 842)*, the determination of whether a lease should be classified as a capital lease, and thereby recorded on the balance sheet, required management to make various assumptions, including the discount rate, the fair market value of the leased assets and the estimated useful life. We were the lessor under a power sales arrangement that was required to be accounted for as an operating lease because it conveyed the right to use our power generating equipment for a stated period of time. The lease revenue from this arrangement is included in other operating revenue on our consolidated statements of operations. We were the lessee under a power purchase arrangement that was required to be accounted for as an operating lease because it conveyed to us the right to use power generating equipment for a stated period of time. It is included in lease expense on our consolidated statements of operations.

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, 2020 was 1.185.

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, 2020, our ECR was 24.86 percent.

As of December 31, 2020, we had approximately $3.0 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Pursuant to 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 $493.2 million of patronage capital to our Utility Members, including the $47.7 million we retired and DMEA forfeited as part of DMEA's withdrawal from membership in us on June 30, 2020.

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 was revised in 2018 to establish a goal of our Board to either defer revenues and incomes as a regulatory liability or recognize previously deferred revenues and incomes 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.

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 a 206 proceeding 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 judge to encourage settlement of material issues and to hold a hearing if settlement is not reached. The settlement proceedings are continuing and settlement offers are being exchanged under the FERC administrative law judge’s guidance and in participation with FERC staff. A fourth settlement conference occurred in December 2020 and a technical conference occurred on January 21, 2021. See Note 15 to the Consolidated Financial Statements in Item 8 for further information.

Our electric sales revenues are derived from electric power sales to our Utility Members and non-member purchasers. Revenues from 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 approved by our Board in October 2020, the A-40 rate schedule will continue in effect for 2021, subject to the 206 proceeding discussed above. For the fifth year in a row, our Class A wholesale rate schedule to our Utility Members has remained unchanged. Our Board also set a goal of reducing our Utility Members rates by eight percent by the end of 2023.

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 electric power 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.

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

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 lease revenues, coal sales and revenue from supplying steam and water. Other operating revenue also includes revenue we receive from two of our Non-Utility Members. The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for 2020 and 2019 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2020	2019	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 1,196,232	$ 1,238,672	$ (42,440)	(3.4)%
Non-member electric sales	102,518	95,401	7,117	7.5 %
Other	53,545	51,399	2,146	4.2 %
Total operating revenues	$ 1,352,295	$ 1,385,472	$ (33,177)	(2.4)%
Energy sales (in MWh):				
Utility Member electric sales	15,884,777	16,412,525	(527,748)	(3.2)%
Non-member electric sales	1,609,088	1,701,476	(92,388)	(5.4)%
	17,493,865	18,114,001	(620,136)	(3.4)%

- Utility Member electric sales decreased, in terms of MWhs sold, primarily due to the withdrawal of DMEA and a slowdown in certain sectors of the economy from the impacts of COVID-19, in particular, from our Utility Members' commercial members. The withdrawal of DMEA in June 2020 resulted in approximately 261,923 MWhs decrease in 2020 compared to 2019, without taking into account the impact of COVID-19.
- Non-member electric sales revenue increased primarily due to rate stabilization measures and more favorable pricing for term sales during the year. In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized $12.1 million of previously deferred revenue during the twelve months ended December 31, 2020 compared to $6.2 million during the same period in 2019. Excluding the effect of these rate stabilization measures, non-member electric sales revenue increased $4.1 million, or 4.6 percent, to $93.3 million in 2020 compared to $89.2 million in 2019. Although non-member sales (in MWhs) decreased, the average non-member rate increased 10.6 percent during the twelve months ended December 31, 2020 compared to the same period in 2019.

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 2020 and 2019 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2020	2019	Amount	Percent
Operating expenses				
Purchased power	$ 335,814	$ 328,921	$ 6,893	2.1 %
Fuel	234,844	280,325	(45,481)	(16.2)%
Production	171,188	209,586	(38,398)	(18.3)%
Transmission	170,933	163,757	7,176	4.4 %
General and administrative	69,796	49,607	20,189	40.7 %
Depreciation, amortization and depletion	185,243	157,734	27,509	17.4 %
Coal mining	11,691	10,027	1,664	16.6 %
Other	15,126	19,090	(3,964)	(20.8)%
Total operating expenses	$ 1,194,635	$ 1,219,047	$ (24,412)	(2.0)%

- Fuel expense includes coal, natural gas, and other fuel consumed at the generating stations. Fuel expense decreased primarily due to lower generation from our generating facilities, fluctuations in fuel prices, and overall decreased demand as a result of impacts from COVID-19. Net generation decreased (in MWhs) 7.9 percent during the twelve months ended December 31, 2020 compared to the same period in 2019. Also included in fuel expense during the twelve months ended December 31, 2019 was an additional environmental reclamation obligation of $22.4 million due to the anticipated revision to the New Horizon mine reclamation plan to accommodate an alternative post mine land use as necessary for final mine reclamation.

- Production expense decreased primarily due to the postponement, or selective performance, of scheduled maintenance activities as a result of impacts from COVID-19. Maintenance activities are expected to be performed at later dates.
- General and administrative expense increased primarily due to an increase in outside professional services, an overall increase in expenses related to general and administration labor and benefits, and an increase in regulatory commission expenses due to various legal actions before FERC.
- Depreciation, amortization, and depletion expense increased primarily due to increased depreciation related to the Collom development, accelerated depletion on the coal reserves at the Colowyo Mine and a change in asset depreciable lives from 2044 to 2030 as a result of the planned early retirement of the Colowyo Mine. Additionally, deferred impairment costs related to the Holcomb Generating Station began to be amortized in January 2020.

Other Income

Other income decreased $16.6 million, or 90.0 percent, to $1.8 million in 2020 compared to $18.4 million in 2019. The decrease was primarily due to a one-time $12.8 million retroactive royalty rate reduction granted to Colowyo Mine by the Office of Natural Resources Revenue during 2019.

Year ended December 31, 2019 compared to year ended December 31, 2018

For discussion of our results of operations comparing the year ended December 31, 2019 to the year ended December 31, 2018, see “Management’s Discussion and Analysis of Results of Operations” in Item 7 of our 2019 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 12, 2020.

Financial Condition as of December 31, 2020 compared to December 31, 2019

Assets

Construction work in progress decreased $75.5 million, or 45.8 percent, to $89.4 million as of December 31, 2020 compared to $164.9 million as of December 31, 2019. The decrease was primarily due to transfers to electric plant in service for completed projects of $224.9 million (primarily for the completion of various transmission projects) partially offset by capital expenditures of $149.4 million (primarily for various transmission improvements and system upgrades).

Net electric plant decreased $261.1 million, or 7.2 percent, to $3.353 billion as of December 31, 2020 compared to $3.614 billion as of December 31, 2019. The decrease was primarily due to the asset impairment at Escalante Station.

Cash and cash equivalents increased $44.1 million, or 53.1 percent, to $127.2 million as of December 31, 2020 compared to $83.1 million as of December 31, 2019. The increase was primarily due to proceeds from the issuance of long-term debt of $425 million (including $200 million drawn on the Revolving Credit Agreement) and proceeds of $88.5 million related to the DMEA withdrawal. These increases in cash and cash equivalents were partially offset by lower short-term borrowings and higher principal payments of long-term debt (including $200 million used to repay draws against the Revolving Credit Agreement).

Restricted cash and investments decreased $25.8 million, or 84.7 percent, to $4.7 million as of December 31, 2020 compared to $30.5 million as of December 31, 2019. The decrease was primarily due our Board unrestricting previously restricted cash related to deferred revenue in response to volatile market conditions.

Regulatory assets increased $213.0 million, or 42.8 percent, to $710.3 million as of December 31, 2020 compared to $497.3 million as of December 31, 2019. The increase was primarily due to the deferral of the $283.0 million impairment loss and other closure costs (including $263.1 million of impaired assets and $19.9 million of other closure costs) related to the early retirement of the Escalante Station, which was retired in 2020. This increase was partially offset by a decrease of $39.3 million in deferred income taxes and amortization of $30.8 million to depreciation, amortization and depletion expense and recovered from our Utility Members through rates.

Equity and Liabilities

Patronage capital equity decreased $52.5 million, or 5.1 percent, to $978.5 million as of December 31, 2020 compared to $1.031 billion as of December 31, 2019. The decrease was due to a patronage capital retirements to our Members of $77.6 million (on June 30, 2020, we retired and DMEA forfeited $47.7 million of patronage capital in connection with DMEA's withdrawal from membership in us) partially offset by margin attributable to us from our Members of $25.1 million.

Long-term debt increased $136.8 million, or 4.5 percent, to $3.200 billion as of December 31, 2020 compared to $3.063 billion as of December 31, 2019 and current maturities of long-term debt increased $6.0 million, or 7.4 percent, to $87.6 million as of December 31, 2020 compared to $81.6 million as of December 31, 2019. The total increase of $142.8 million was primarily due to proceeds from issuance of long-term debt of $425 million (including $200 million drawn on the Revolving Credit Agreement) partially offset by debt payments of $282.8 million (including $200 million used to repay draws against the Revolving Credit Agreement).

Short-term borrowings decreased $252.3 million, or 100.0 percent, to $0 as of December 31, 2020 compared to $252.3 million as of December 31, 2019. The decrease was due to a temporary market disruption in the commercial paper market which began around March 16, 2020 and continued through early April. During that period of time which saw elevated Tier 2 borrowing rates and shortened tenors, we borrowed under our Revolving Credit Agreement in the amount of $200.0 million and paid down the commercial paper by $200.0 million. On June 24, 2020 we entered into the First Mortgage Obligations, Series 2020A in the amount of $125.0 million with CoBank as well as the First Mortgage Obligations, Series 2020B in the amount of $100.0 million with CFC. Proceeds from these two borrowings were used to repay all remaining outstanding commercial paper.

Regulatory liabilities increased $102.8 million, or 84.1 percent, to $225.0 million as of December 31, 2020 compared to $122.2 million as of December 31, 2019. The increase was primarily due to the deferral of the recognition of $110.2 million of other income and $5.2 million gain on sale of assets in connection with the June 30, 2020 withdrawal of DMEA from membership in us. This increase was partially offset by the recognition of $12.1 million of previously deferred non-member electric sales revenues and amortization of $0.5 million to interest expense related to the deferred realized gain on an interest rate swap which is being recognized over the twelve year term of the First Mortgage Obligations, Series 2017A.

Deferred income tax liability decreased $39.3 million, or 66.8 percent, to $19.6 million as of December 31, 2020 compared to $58.9 million as of December 31, 2019. The decrease in the deferred income tax liability was primarily due to the decrease in the valuation allowance. Of the $39.3 million decrease, $51,000 was recognized as a deferred income tax benefit and the balance was deferred and reflected as a decrease in the regulatory asset established for deferred income tax expense.

Asset retirement obligations increased $50.5 million, or 66.2 percent, to $127.0 million as of December 31, 2020 compared to $76.5 million as of December 31, 2019. The increase was primarily due to the recording of an additional reclamation obligation of $59.5 million at the Colowyo Mine during 2020 and accretion of $2.5 million partially offset by the transfer of the Fort Union asset retirement obligation of $2.3 million in December 2020 to Basin as part of our withdrawal from membership in WFA. The increase in the Colowyo Mine reclamation obligation was primarily related to the review of and change in acceptable post-mine topography in the overall evaluation of South Taylor pit at the Colowyo Mine. As the South Taylor Pit is nearing its end of life, we reviewed approved post-mine topography which was accepted by the Colorado Division of Reclamation, Mining and Safety for the West pit and determined a change was necessary for the South Taylor pit. The West pit is currently in final reclamation.

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, 2020, we had $127.2 million in cash and cash equivalents. Our committed credit arrangement as of December 31, 2020 is as follows (dollars in thousands):

	Authorized Amount		Available December 31, 2020
Revolving Credit Agreement	$ 650,000	(1)	$ 650,000

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

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 $500 million of the commercial paper back-up sublimit remained available as of December 31, 2020.

The Revolving Credit Agreement is secured under the Master Indenture and has a maturity date of April 25, 2023, unless extended as provided therein. 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. Upon discontinuation of the LIBOR rate, the Revolving Credit Agreement provides for CFC and us to endeavor to establish an alternative rate that gives due consideration to the then prevailing market convention for determining a rate of interest for syndicated loans in the United States. Upon discontinuation of the LIBOR rate and if no alternative rate has been established by CFC and us, all funds advanced will be at base rate loans. We had no outstanding borrowings as of December 31, 2020.

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, 2020, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of December 31, 2020, we had no commercial paper outstanding and $500 million available on the commercial paper back-up sublimit.

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

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, 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, 2020 compared to year ended December 31, 2019

Operating activities. Net cash provided by operating activities was $330.9 million in 2020 compared to $233.3 million in 2019, an increase of $97.6 million. The increase in cash provided by operating activities in 2020 compared to 2019 was primarily due to proceeds of $88.5 million related to the DMEA withdrawal and the timing of payment of trade and purchased power payables.

Investing activities. Net cash used in investing activities was $120.3 million in 2020 compared to $203.4 million in 2019, a decrease of $83.1 million. The decrease was primarily due to proceeds from the sale of electric plant related to the DMEA withdrawal and a reduction in generation and transmission improvements and system upgrades.

Financing activities. Net cash used in financing activities was $192.3 million in 2020 compared to $43.7 million in 2019, an increase in net cash used in financing activities of $148.6 million. The increase was primarily due to lower short-term borrowings of $300.5 million, higher principal payments of long-term debt of $186.7 million and higher patronage capital retirements to our Utility Members of $47.6 million (due primarily to the $47.7 million retirement of patronage capital in connection with DMEA's June 30, 2020 withdrawal from membership in us). These increases in net cash used in financing activities were partially offset by higher proceeds from issuance of long-term debt of $390.1 million in 2020 compared to the previous year.

Year ended December 31, 2019 compared to year ended December 31, 2018

For discussion of our cash flow comparing 2019 to 2018, see “Management’s Discussion and Analysis of Liquidity and Capital Resources—Cash Flow” in Item 7 of our 2019 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 12, 2020.

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 2021 through 2025, we forecast that we may invest approximately $799 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):

	2021	2022	2023	2024	2025	Total
Generation	$ 63,436	$ 46,507	$ 27,021	$ 16,594	$ 43,764	$ 197,322
Transmission	76,262	90,605	65,569	96,610	99,729	428,775
General Plant	37,016	32,252	44,823	28,691	28,741	171,523
Other (1)	800	330	330	330	—	1,790
Total Capital Expenditures	$ 177,514	$ 169,694	$ 137,743	$ 142,225	$ 172,234	$ 799,410

(1) Includes mining and non-utility assets.

Our actual capital expenditures depend on a variety of factors, including assumptions related to our Responsible Energy Plan and 2020 Electric Resource Plan, 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.

We are subject to extensive federal, state and local environmental requirements. Furthermore, it is expected with a change in the federal administration 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 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. See “BUSINESS – ENVIRONMENTAL REGULATION” and “RISK FACTORS - Environmental Risk.”

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

Contractual Commitments

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our owned and leased generation and transmission facilities, the financing of our operations and other matters. The following table summarizes our long-term contractual obligations as of December 31, 2020 (dollars in thousands):

	Payments Due by Period				
Obligations	Total	Less Than 1 Year	1 - 3 Years	4 - 5 Years	More Than 5 Years
Long-term Indebtedness					
Principal (1)	$ 3,287,767	$ 87,587	$ 186,111	$ 435,237	$ 2,578,832
Interest (2)	2,247,398	141,155	270,354	249,239	1,586,650
Operating Lease Obligations	2,412	580	716	384	732
Construction Obligations	18,640	9,521	9,119	—	—
Coal Purchase Obligations	241,891	64,637	19,784	14,862	142,608
Total	$ 5,798,108	$ 303,480	$ 486,084	$ 699,722	$ 4,308,822

(1) Includes $250 million bullet maturity for the First Mortgage Bonds, Series 2014 E-1 due in 2024.
(2) Includes interest expense related to approximately $449.6 million of variable rate long-term debt. Future variable rates are based on Bloomberg surveys and internal forecasts as of December 31, 2020.

We expect to fund these obligations with cash flows from operations, borrowings under our commercial paper program and the issuance of additional long-term debt.

Indebtedness. As of December 31, 2020, we had $3.3 billion in outstanding obligations, including approximately $3.0 billion of debt outstanding secured on a parity basis under our Master Indenture, one unsecured loan agreement totaling $19.6 million and the Springerville certificates totaling $334.0 million (which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease). Our debt secured by the lien of our Master Indenture includes notes payable to CFC and CoBank (with the exception of one unsecured note), the First Mortgage Obligations, Series 2009C, the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, the First Mortgage Bonds, Series 2014E-1 and E-2, the

First Mortgage Bonds, Series 2016A, the First Mortgage Obligations, Series 2017A, pollution control revenue bonds, and amounts outstanding, if any, under the Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under our Master Indenture.

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 $500 million of the commercial paper back-up sublimit remained available as of December 31, 2020. As of December 31, 2020, we had $650 million of availability under the Revolving Credit Agreement.

Construction Obligations. We have commitments to complete certain construction projects associated with improving the reliability of the generating facilities and the transmission system.

Coal Purchase Obligations. We have commitments to purchase coal for our generating facilities under long-term contracts that expire between 2021 and 2041. 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. Our coal purchase obligations exclude any purchases we have with our subsidiaries.

Rating Triggers

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s, “A- (stable outlook)” by S&P, and “A- (stable outlook)” by Fitch. Our current short-term ratings are “P-2” by Moody’s, “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.

Off Balance Sheet Arrangements

We have no off-balance sheet arrangements.

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, 2020 and 2019 are as follows:

	December 31, 2020		December 31, 2019	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,308,715	$ 3,908,497	$ 3,166,472	$ 3,608,341

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 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 2020, these resources provided approximately 6.5 percent of our energy available for sale. We expect the use of our natural gas-fired facilities to increase with the addition of new renewable resources and the closure of our coal-fired generating facilities.

Risk Management

We have implemented 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 implemented a 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, 2020, we were exposed to the risk of changes in interest rates related to our $449.6 million of variable rate debt, comprised of $152.6 million of variable rate CFC notes and $297.0 million of variable rate CoBank notes. As of December 31, 2020, the weighted average interest rate on this variable rate debt was 1.74 percent.

Prior to discontinuation of the LIBOR rate, we will work with CoBank and CFC to establish an alternative rate, as stipulated in the loan agreements.

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, 2020, we had 13.6 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, 2020 and 2019, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 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 5, 2021

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

As of December 31,	2020	2019
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 6,254,652	$ 6,090,392
Construction work in progress	89,447	164,924
Total electric plant	6,344,099	6,255,316
Less allowances for depreciation and amortization	(2,991,393)	(2,641,470)
Net electric plant	3,352,706	3,613,846
Other plant	456,924	409,051
Less allowances for depreciation, amortization and depletion	(133,012)	(113,607)
Net other plant	323,912	295,444
Total property, plant and equipment	3,676,618	3,909,290
Other assets and investments		
Investments in other associations	162,975	161,945
Investments in and advances to coal mines	2,799	19,681
Restricted cash and investments	4,682	30,516
Other noncurrent assets	14,889	8,654
Total other assets and investments	185,345	220,796
Current assets		
Cash and cash equivalents	127,187	83,070
Restricted cash and investments	205	182
Deposits and advances	32,012	28,434
Accounts receivable—Members	96,637	105,371
Other accounts receivable	20,570	28,039
Electric plant held for sale	4,877	—
Coal inventory	55,762	50,191
Materials and supplies	82,119	93,632
Total current assets	419,369	388,919
Deferred charges		
Regulatory assets	710,268	497,279
Prepayment—NRECA Retirement Security Plan	21,490	26,862
Other	33,646	42,672
Total deferred charges	765,404	566,813
Total assets	**$ 5,046,736**	**$ 5,085,818**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 978,519	$ 1,031,063
Accumulated other comprehensive loss	(5,714)	(1,518)
Noncontrolling interest	114,851	111,717
Total equity	1,087,656	1,141,262
Long-term debt	3,200,181	3,063,351
Total capitalization	4,287,837	4,204,613
Current liabilities		
Member advances	16,592	18,025
Accounts payable	98,654	99,033
Short-term borrowings	—	252,323
Accrued expenses	40,736	43,761
Current asset retirement obligations	11,044	2,460
Accrued interest	27,520	29,716
Accrued property taxes	32,794	29,129
Current maturities of long-term debt	87,587	81,555
Total current liabilities	314,927	556,002
Deferred credits and other liabilities		
Regulatory liabilities	224,953	122,169
Deferred income tax liability	19,591	58,937
Asset retirement and environmental reclamation obligations	127,045	76,454
Other	54,600	56,399
Total deferred credits and other liabilities	426,189	313,959
Accumulated postretirement benefit and postemployment obligations	17,783	11,244
Total equity and liabilities	**$ 5,046,736**	**$ 5,085,818**

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,	2020	2019	2018
Operating revenues			
Member electric sales	$ 1,196,232	$ 1,238,672	$ 1,235,872
Non-member electric sales	102,518	95,401	34,763
Other	53,545	51,399	50,202
	1,352,295	1,385,472	1,320,837
Operating expenses			
Purchased power	335,814	328,921	343,509
Fuel	234,844	280,325	237,721
Production	171,188	209,586	212,917
Transmission	170,933	163,757	161,652
General and administrative	69,796	49,607	33,046
Depreciation, amortization and depletion	185,243	157,734	154,975
Coal mining	11,691	10,027	637
Other	15,126	19,090	14,987
	1,194,635	1,219,047	1,159,444
Operating margins	**157,660**	**166,425**	**161,393**
Other income			
Interest	4,218	6,175	5,294
Capital credits from cooperatives	11,803	9,799	27,373
Other	1,831	18,427	5,131
	17,852	34,401	37,798
Interest expense			
Interest	151,423	160,169	162,350
Interest charged during construction	(6,088)	(8,699)	(8,646)
	145,335	151,470	153,704
Income tax benefit	(534)	(307)	(534)
Net margins including noncontrolling interest	30,711	49,663	46,021
Net margin attributable to noncontrolling interest	(5,590)	(4,354)	(3,287)
Net margins attributable to the Association	**$ 25,121**	**$ 45,309**	**$ 42,734**

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,	2020	2019	2018
Net margins including noncontrolling interest	$ 30,711	$ 49,663	$ 46,021
Other comprehensive income (loss):			
Unrealized gain on securities available for sale	—	—	—
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,332	(1,341)	456
Reclassification of unrealized gain on securities available for sale included in net margin	—	—	(159)
Amortization of actuarial (gain) loss on postretirement benefit obligation included in net margin	1,845	(338)	288
Unrecognized prior service cost (credit)	(7,373)	(214)	—
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	(4,196)	(1,893)	585
Comprehensive income including noncontrolling interest	26,515	47,770	46,606
Net comprehensive income attributable to noncontrolling interest	(5,590)	(4,354)	(3,287)
Comprehensive income attributable to the Association	**$ 20,925**	**$ 43,416**	**$ 43,319**

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,	2020	2019	2018
Patronage capital equity at beginning of period	$ 1,031,063	$ 1,015,754	$ 1,003,020
Net margins attributable to the Association	25,121	45,309	42,734
Retirement of patronage capital	(77,665)	(30,000)	(30,000)
Patronage capital equity at end of period	**978,519**	**1,031,063**	**1,015,754**
Accumulated other comprehensive income (loss) at beginning of period	(1,518)	375	(210)
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,332	(1,341)	456
Reclassification adjustment for unrealized gain on securities available for sale included in net margin	—	—	(159)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net margin	1,845	(338)	288
Unrecognized prior service cost	(7,373)	(214)	—
Accumulated other comprehensive income (loss) at end of period	**(5,714)**	**(1,518)**	**375**
Noncontrolling interest at beginning of period	111,717	110,169	111,295
Net comprehensive income attributable to noncontrolling interest	5,590	4,354	3,287
Equity distribution to noncontrolling interest	(2,456)	(2,806)	(4,413)
Noncontrolling interest at end of period	**114,851**	**111,717**	**110,169**
Total equity at end of period	**$ 1,087,656**	**$ 1,141,262**	**$ 1,126,298**

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,	2020	2019	2018
Operating activities			
Net margins including noncontrolling interest	$ 30,711	$ 49,663	$ 46,021
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	185,243	157,734	154,975
Amortization of intangible asset	—	3,662	7,324
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,372
Amortization of debt issuance costs	2,460	2,375	2,641
Impairment loss	274,645	37,067	—
Deferred impairment loss and other closure costs	(283,047)	(37,067)	—
Deferred membership withdrawal income	110,165	—	—
Deferred revenue	—	—	51,679
Recognition of deferred revenue	(12,136)	(6,153)	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,268)	(1,276)	(18,090)
Changes in operating assets and liabilities:			
Accounts receivable	17,358	2,383	(5,922)
Coal inventory	(5,571)	5,692	(8,080)
Materials and supplies	(40)	154	(3,576)
Accounts payable and accrued expenses	(844)	1,136	(10,434)
Accrued interest	(2,196)	(2,354)	(782)
Accrued property taxes	3,665	547	1,446
Other	6,402	14,328	(6,297)
Net cash provided by operating activities	**330,919**	**233,263**	**216,277**
Investing activities			
Purchases of plant	(142,152)	(212,815)	(280,712)
Sale of electric plant	26,000	—	—
Changes in deferred charges	(4,885)	9,347	(2,233)
Proceeds from other investments	733	65	67
Net cash used in investing activities	**(120,304)**	**(203,403)**	**(282,878)**
Financing activities			
Changes in Member advances	(7,837)	(4,177)	(1,717)
Payments of long-term debt	(282,757)	(96,099)	(133,848)
Proceeds from issuance of long-term debt	425,000	34,910	150,090
Debt issuance costs	(637)	(13)	(10,697)
Increase (decrease) in short-term borrowings, net	(252,323)	48,178	59,478
Retirement of patronage capital	(70,881)	(23,303)	(15,339)
Equity distribution to noncontrolling interest	(2,456)	(2,806)	(4,413)
Other	(418)	(372)	(328)
Net cash provided by (used in) financing activities	**(192,309)**	**(43,682)**	**43,226**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**18,306**	**(13,822)**	**(23,375)**
Cash, cash equivalents and restricted cash and investments – beginning	**113,768**	**127,590**	**150,965**
Cash, cash equivalents and restricted cash and investments – ending	**$ 132,074**	**$ 113,768**	**$ 127,590**
Supplemental cash flow information:			
Cash paid for interest	$ 152,570	$ 161,460	$ 161,809
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 440	$ (96)	$ (44)

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.

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 2020, 2019 and 2018, total megawatt-hours sold were 17.5, 18.1 and 18.2 million, respectively, of which 90.8, 90.6 and 90.0 percent, respectively, were sold to Utility Members. Total revenue from electric sales was $1.3 billion for 2020, 2019 and 2018 of which 92.1, 92.8, and 97.3 percent in 2020, 2019 and 2018, respectively, was from Utility Member sales. Energy resources were provided by our generation and purchased power, of which 58.2, 61.5 and 58.9 percent in 2020, 2019 and 2018, respectively, were from our generation.

Revenue from one Utility Member, United Power, Inc. ("United Power"), was $215.2 million, or 18.0 percent, of our Utility Member revenue and 15.9 percent of our total operating revenues in 2020. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues in 2020.

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 had direct ownership and investment in coal mines.

We, including our subsidiaries, employ 1,304 people, of which 246 are subject to collective bargaining agreements. As of December 31, 2020, the collective bargaining agreements for our operations and maintenance electrical workers and clerical electrical workers on the Western Slope of Colorado with 246 employees represented will expire in April 2021 and we are actively working on renewing such agreements.

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 had direct ownership and investments 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. 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. There were no impairments of long-lived assets recognized in 2018. 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: We are subject to the accounting requirements related to regulated operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board 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. Prior to September 3, 2019, our Board had sole budgetary and rate-setting 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. 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, 2020	December 31, 2019
Regulatory assets		
Deferred income tax expense (1)	$ 19,641	$ 58,937
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	81,424	83,714
Goodwill – J.M. Shafer (3)	46,296	49,145
Goodwill – Colowyo Coal (4)	36,161	37,194
Deferred debt prepayment transaction costs (5)	132,302	140,931
Deferred Holcomb expansion impairment loss (6)	88,819	93,494
Unrecovered plant (7)	305,625	33,864
Total regulatory assets	710,268	497,279
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	3,293	3,744
Deferred revenues (9)	63,717	75,853
Membership withdrawal (10)	157,943	42,572
Total regulatory liabilities	224,953	122,169
Net regulatory asset	$ 485,315	$ 375,110

(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. In July 2019, our Board took action for the early retirement of the Nucla Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement of the Nucla Generating Station, we recognized an impairment loss of $37.1 million during the third quarter of 2019. On September 19, 2019, the Nucla Generating Station was officially retired from service. The deferred impairment loss for the Nucla Generating Station is being amortized to depreciation, amortization and depletion expense over the 3.3-year period ending in December 2022 and recovered from our Utility Members in rates. In January 2020, our Board approved the early retirement of the Escalante Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement, we recognized an impairment loss of $283.0 million in 2020 (including $263.1 million of impaired assets and $19.9 million of other closure costs). The deferred impairment loss for

Escalante Generating Station will be amortized to depreciation, amortization and depletion expense beginning in 2021 through the end of 2045, which was the depreciable life of Escalante Generating Station, and is expected to be recovered from our Utility Members through rates. The annual amortization is expected to approximate the former 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) Represents deferral of the recognition of non-member electric sales revenues. These deferred non-member electric sales revenues will be refunded to Utility Members through reduced rates when recognized in non-member electric sales revenue in future periods.

(10) Represents the deferral of the recognition of other income recorded related to the June 30, 2016 withdrawal of a former Utility Member from membership in us and the June 30, 2020 withdrawal of Delta-Montrose Electric Association ("DMEA") from membership in us. In connection with the DMEA withdrawal, we recognized $110.2 million of other income and $5.2 million of gain on sale of assets which was subsequently deferred. The total deferred membership withdrawal income will be refunded to Utility Members through reduced rates when recognized in other income in future periods.

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 was 4.6 percent for 2020 and 4.7 percent for 2019 and 2018. The amount of interest capitalized during construction was $6.1, $8.7 and $8.6 million during 2020, 2019 and 2018, 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, 2020	December 31, 2019
Basin Electric Power Cooperative	$ 118,295	$ 117,368
National Rural Utilities Cooperative Finance Corporation - patronage capital	11,933	11,761
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,221	15,953
CoBank, ACB	11,141	10,201
Western Fuels Association, Inc.	2,283	2,409
Other	4,102	4,253
Investments in other associations	$ 162,975	$ 161,945

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 2020, 2019 or 2018.

INVESTMENTS IN AND ADVANCES TO COAL MINES: We had direct ownership and investments in coal mines to support our coal generating resources. We were a member of Trapper Mining, Inc. ("Trapper Mining"), which is organized as a cooperative and is the owner and operator of the Trapper Mine near Craig, Colorado. In December 2020, upon termination of our coal supply agreement with Trapper Mining, we withdrew from our membership in Trapper Mining. Our investment in Trapper Mining was recorded using the equity method. In addition, we had ownership in Western Fuels Association, Inc. ("WFA"), which is an owner of Western Fuels-Wyoming, Inc. ("WFW"), the owner and operator of the Dry Fork Mine near Gillette, Wyoming. Dry Fork Mine provides coal to the Laramie River Generating Station (owned by the participants of MBPP). In December 2020, we withdrew from membership in WFA. We, through our undivided interest in the jointly owned facility MBPP, advance funds to the Dry Fork Mine.

Investments in and advances to coal mines are as follows (dollars in thousands):

	December 31, 2020	December 31, 2019
Investment in Trapper Mine	$ —	$ 15,881
Advances to Dry Fork Mine	2,799	3,800
Investments in and advances to coal mines	$ 2,799	$ 19,681

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, 2020	December 31, 2019
Cash and cash equivalents	$ 127,187	$ 83,070
Restricted cash and investments - current	205	182
Restricted cash and investments - noncurrent	4,682	30,516
Cash, cash equivalents and restricted cash and investments	$ 132,074	$ 113,768

Our Board Policy for Financial Goals and Capital Credits was revised in 2018 to provide that our Board will endeavor to fund an internally restricted cash account for the purpose of cash funding deferred revenues and incomes held as regulatory liabilities. In connection with such policy, our Board internally restricted cash in the amount of $25.5 million as of December 31, 2019 which was included in restricted cash and investments – noncurrent. Our Board may, at any time and for any reason, unrestrict any internally restricted cash. On March 10, 2020, our Board took action to unrestrict the $25.5 million balance of the restricted cash in response to volatile market conditions.

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. At December 31, 2020, the cost and estimated fair value of the investments were $0.5 million. At December 31, 2019, the cost and estimated fair value of the investments were $0.7 million.

INVENTORIES: Coal inventories at our owned generating facilities are stated at LIFO (last-in, first-out) cost and were $24.2 and $21.4 million as of December 31, 2020 and 2019, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2020, we realized lower coal fuel expense of $0.9 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 if approved by our Board and subject to FERC approval.

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, 2020	December 31, 2019
Preliminary surveys and investigations	$ 12,886	$ 21,261
Advances to operating agents of jointly owned facilities	2,071	3,917
Operating lease right-of-use assets	7,985	7,622
Other	10,704	9,872
Total other deferred charges	$ 33,646	$ 42,672

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.

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 $30.0 million for these easements from 2021 through the individual easement terms ending between 2036 and 2040. The present value of the remaining easement payments was $20.0 and $20.5 million as of December 31, 2020 and December 31, 2019, 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, 2020	December 31, 2019
Transmission easements	$ 19,983	$ 20,549
Operating lease liabilities - noncurrent	1,590	1,846
Contract liabilities (unearned revenue) - noncurrent	3,702	4,217
Customer deposits	7,712	3,015
Financial liabilities - reclamation	12,081	12,091
Other	9,532	14,681
Total other deferred credits and other liabilities	$ 54,600	$ 56,399

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 agreement. 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 lease revenues, coal sales and revenue from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station. Other operating revenue also includes revenue we receive from two of our Non-Utility Members. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. Transmission revenue is received from our membership in the Southwest Power Pool, a regional transmission organization. The lease revenue is primarily from a power sales arrangement, which expired on June 30, 2019, that was required to be accounted for as an operating lease since it conveyed to a third party the right to use power generating equipment for a stated period of time. See Note 11 – Leases. Coal sales revenue results from the sale of coal from the Colowyo Mine 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 $2.2 and $1.6 million at December 31, 2020 and 2019, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was a credit of $0.1 million and $0.4 million in 2020 and 2019, respectively, and an expense of $0.6 million in 2018.

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, 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 %	$ 3,691,021	$ (1,898,984)	$ 1,792,037
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)				$ 6,254,652	$ (2,991,393)	3,263,259
Construction work in progress						89,447
Electric plant						$ 3,352,706

At December 31, 2019, 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 %	$ 3,681,886	$ (1,599,528)	$ 2,082,358
Transmission plant	1.11 %	to	2.09 %	1,679,534	(600,740)	1,078,794
General plant	1.46 %	to	9.53 %	472,592	(321,304)	151,288
Other	2.75 %	to	10.00 %	256,380	(119,898)	136,482
Electric plant in service (at cost)				$ 6,090,392	$ (2,641,470)	3,448,922
Construction work in progress						164,924
Electric plant						$ 3,613,846

At December 31, 2020, we had $18.6 million of commitments to complete construction projects, of which approximately $9.5, $5.8 and $3.4 million are expected to be incurred in 2021, 2022 and 2023, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2020 (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 %	$ 395,265	$ 251,621	$ 643
MBPP - Laramie River Station	27.13 %	487,185	302,537	2,785
Total		$ 882,450	$ 554,158	$ 3,428

OTHER PLANT: Other plant consists of mine assets (discussed below) and non-utility assets (which consist of piping and equipment specifically related to providing steam and water from the Escalante Generating Station to a third party for their use in the production of paper).

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, which is the owner and operator of the New Horizon Mine near Nucla, Colorado. New Horizon Mine is in mine reclamation and no longer produces coal. Elk Ridge also owns Colowyo Coal, which is the owner and operator of the Colowyo Mine, a large surface coal mine near Craig, Colorado. The expenses related to this 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, 2020	December 31, 2019
Colowyo Mine assets	$ 415,739	$ 356,612
New Horizon Mine assets	38,388	38,949
Fort Union Mine assets	—	846
Accumulated depreciation and depletion	(132,730)	(106,337)
Net mine assets	321,397	290,070
Non-utility assets	2,797	12,644
Accumulated depreciation	(282)	(7,270)
Net non-utility assets	2,515	5,374
Net other plant	$ 323,912	$ 295,444

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):

	2020	2019
Obligations at beginning of period	$ 78,914	$ 56,772
Liabilities incurred	2,527	23,290
Liabilities settled	(3,689)	(1,090)
Accretion expense	2,506	2,863
Change in cash flow estimate	57,831	(2,921)
Total obligations at end of period	$ 138,089	$ 78,914
Less current obligations at end of period	(11,044)	(2,460)
Long-term obligations at end of period	$ 127,045	$ 76,454

In 2020, we recorded an additional reclamation liability of $59.5 million. The increase in the liability was primarily related to the review of and change in acceptable post-mine topography in the overall evaluation of South Taylor pit at the Colowyo Mine. As the South Taylor Pit is nearing its end of life, we reviewed approved post-mine topography which was accepted by the Colorado Division of Reclamation, Mining and Safety for the West pit and determined a change was necessary for the South Taylor pit. The West pit is currently in final reclamation. In 2019, we recorded an additional reclamation obligation liability of $22.4 million due to anticipated revision to the New Horizon Mine reclamation plan to accommodate an alternative post mine land use as necessary for final mine 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, 2020 and December 31, 2019.

Accounts Receivable

We record accounts receivable for our unconditional rights to consideration arising from our performance under contracts with our Members and other parties. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible. See Note 10 – Revenue.

Contract liabilities (unearned revenue)

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. We recognized $1.2 million of this unearned revenue in 2020 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, 2020	December 31, 2019
Accounts receivable - Members	$ 96,637	$ 105,371
Other accounts receivable - trade:		
Non-member electric sales	5,231	4,727
Other	9,785	20,628
Total other accounts receivable - trade	15,016	25,355
Other accounts receivable - nontrade	5,554	2,684
Total other accounts receivable	$ 20,570	$ 28,039
Contract liabilities (unearned revenue)	$ 6,025	$ 7,041

NOTE 6 – LONG-TERM DEBT

We have $3.2 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 $19.6 million as of December 31, 2020. 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, 2020. As of December 31, 2020, we had $650 million in availability (including $500 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

On June 24, 2020, we entered into two term loan agreements. A term loan agreement was entered into with CoBank under which we issued our First Mortgage Obligations, Series 2020A consisting of a variable rate borrowing in the amount of $125 million. A term loan agreement was entered into with CFC under which we issued our First Mortgage Obligations, Series 2020B consisting of fixed rate borrowings in the amount of $50 million and variable rate borrowings in the amount of $50 million. Proceeds from the two borrowings were utilized to pay down commercial paper borrowings, repay draws outstanding under the Revolving Credit Agreement and for general corporate purposes.

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

	December 31, 2020	December 31, 2019
Mortgage notes payable		
3.66% to 8.08% CFC, due through 2028	$ 115,583	$ 73,859
2.63% to 4.43% CoBank, ACB, due through 2042	220,704	235,900
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	250,000	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	44,000
Variable rate CFC, as determined by CFC, due through 2026	386	443
Variable rate CFC, LIBOR-based term loan, due through 2049	152,220	102,220
Variable rate CoBank, ACB, LIBOR-based term loans, due through 2044	297,039	172,039
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	333,983	371,211
Total long-term debt	$ 3,308,715	$ 3,166,472
Less debt issuance costs	(25,590)	(27,412)
Less debt discounts	(9,659)	(9,906)
Plus debt premiums	14,302	15,752
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,287,768	$ 3,144,906
Less current maturities	(87,587)	(81,555)
Long-term debt	$ 3,200,181	$ 3,063,351

Annual maturities of total long-term debt adjusted for debt issuance costs, discounts and premiums at December 31, 2020 are as follows (dollars in thousands):

2021	$ 87,587
2022	93,034
2023	93,078
2024 (1)	346,069
2025	89,168
Thereafter	2,578,832
	$ 3,287,768

(1) Includes $250 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):

	2020	2019
Commercial paper outstanding, net of discounts	$ —	$ 252,323
Weighted average interest rate	— %	1.88 %

At December 31, 2020, $500 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.

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, 2020		December 31, 2019	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 491	$ 478	$ 715	$ 654

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 $95.0 million and $79.0 million as of December 31, 2020 and 2019, 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, 2020		December 31, 2019	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,308,715	$ 3,908,497	$ 3,166,472	$ 3,608,341

NOTE 9 – INCOME TAXES

We had an income tax benefit of $0.5 million, $0.3 million and $0.5 million in 2020, 2019 and 2018, respectively. These income tax benefits are due to our election to receive an alternative minimum tax credit refund in lieu of recognizing bonus depreciation.

The liability method of accounting for income taxes is utilized 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, 2020	December 31, 2019
Deferred tax assets		
Safe harbor lease receivables	$ 11,604	$ 14,552
Net operating loss carryforwards	116,430	116,797
Alternative minimum tax credit carryforwards	—	308
Deferred revenues and membership withdrawal	57,704	28,185
Operating lease liabilities	123,459	131,817
Other	39,277	26,587
	348,474	318,246
Less valuation allowance	—	(30,468)
	348,474	287,778
Deferred tax liabilities		
Basis differences- property, plant and equipment	167,243	129,427
Capital credits from other associations	30,809	32,789
Deferred debt prepayment transaction costs	31,488	33,542
Operating lease right-of-use assets	133,850	136,930
Other	4,675	14,027
	368,065	346,715
Net deferred tax liability	$ (19,591)	$ (58,937)

Net deferred tax liabilities decreased by $39.3 million in 2020. Of this amount, $51,000 is recognized as a deferred income tax benefit and the balance is deferred and reflected as a decrease in the regulatory asset established for deferred income tax expense. The accounting for regulatory assets is discussed further in Note 2—Accounting for Rate Regulation. The regulatory asset balance associated with deferred income tax expense under the liability method is $19.6 million and $58.9 million at December 31, 2020 and 2019, respectively.

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

	2020	2019	2018
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	(56.69)	(11.33)	3.57
Deferred revenues and membership withdrawal	(117.60)	3.23	(28.78)
Operating liabilities, net of right-of-use assets (1)	21.02	11.29	—
Valuation Allowance	(121.38)	67.24	—
Other book tax differences	71.34	(2.43)	24.42
Impairment	81.88	—	—
Regulatory treatment of deferred taxes	119.29	(68.68)	(0.46)
Effective tax rate	(2.14)%	(0.68)%	(1.25)%

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

We had taxable income of $4.5 million for 2020. At December 31, 2020, we have a federal net operating loss carryforward of $491.0 million of which pre-2018 tax years are subject to expiration periods between 2031 and 2037. We have $355.0 million of state net operating loss carryforwards subject to expiration periods between 2020 and 2037. 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 2017 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 electric power 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 electric power sales to our Utility Members are primarily from our Class A rate schedule. 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, subject to FERC approval. 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.

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):

	2020	2019	2018
Non-member electric sales:			
Long-term contracts	$ 46,172	$ 47,224	$ 45,314
Short-term contracts	44,210	42,024	41,127
Recognition (deferral) of revenue, net	12,136	6,153	(51,678)
Coal Sales	7,326	6,662	1,075
Other	46,219	44,737	49,127
Total non-member electric sales and other operating revenue	$ 156,063	$ 146,800	$ 84,965

Non-member electric sales

Revenues from electric power sales to non-members are primarily from long-term contracts and short-term market sales. We deferred $51.7 million of non-member electric sales revenue for the year ended December 31, 2018, as directed by our Board. We recognized a net of $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.

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.

Other operating revenue

Other operating revenue consists primarily of wheeling, transmission and lease revenues, coal sales and revenue from supplying steam and water. Other operating revenue also includes revenue we receive from two of our Non-Utility Members. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines in the Western Interconnection (payments are received in accordance with the contract terms which is within 20 days of the date of receipt of the invoice). 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). Steam and water revenue is derived from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station (payments from the customer are received in accordance with the contract terms which is less than 15 days of receipt of the invoice). Each of these services or goods are provided over time and progress toward completion of our performance obligations are measured using the output method. Lease revenue is primarily from a power sales arrangement, which expired on June 30, 2019, that was required to be accounted for as an operating lease since the arrangement conveyed the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. We have an obligation to deliver coal and progress 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 and had a lease agreement for the right to use power generating equipment at Brush Generating Station. Under the power purchase arrangement at the Brush Generating Station that expired on December 31, 2019, we were required to account for the arrangement as an operating lease since it conveyed to us the right to direct the use of 70 megawatts at the Brush Generating Station and whereby we provided our own natural gas for generation of electricity. We did not renew this power purchase arrangement.

Rent expense for all short-term and long-term operating leases was $2.8 million in 2020 and $7.4 million in 2019. Rent expense is included in operating expenses on our consolidated statements of operations. As of December 31, 2020, 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, 2020	December 31, 2019
Operating leases		
Operating lease right-of-use assets	$ 9,223	$ 8,376
Less: Accumulated amortization	(1,238)	(754)
Net operating lease right-of-use assets	$ 7,985	$ 7,622
Operating lease liabilities – current	$ (526)	$ (5,533)
Operating lease liabilities – noncurrent	(1,590)	(1,846)
Total operating lease liabilities	$ (2,116)	$ (7,379)
Operating leases		
Weighted average remaining lease term (years)	7.6	9.5
Weighted average discount rate	3.84 %	3.80 %

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

Year 1	$	580
Year 2		379
Year 3		337
Year 4		304
Year 5		80
Thereafter		732
Total lease payments	$	2,412
Less imputed interest		(296)
Total	$	2,116

Leasing Arrangements As Lessor

We have lease agreements as lessor for certain operational assets and had a lease agreement as lessor for power generating equipment at the J.M. Shafer Generating Station. Under the power sales arrangement at the J.M. Shafer Generating Station that expired on June 30, 2019, we were required to account for the arrangement as an operating lease since it conveyed to a third party the right to direct the use of 122 megawatts of the 272 megawatt generating capability of the J.M. Shafer Generating Station whereby the third party provided its own natural gas for generation of electricity. The revenue from these lease agreements of $6.6 million in 2020 and $12.1 million in 2019 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 25.7, 24.7 and 31.1 percent in 2020, 2019 and 2018, respectively, of the coal for the Yampa Project. Our 26.57 percent share of coal purchases from Trapper Mining was $20.2, $18.6 and $18.2 million in 2020, 2019 and 2018, 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 of $0.0 and $15.9 million at December 31, 2020 and 2019, respectively, is included in investments in and advances to coal mines on our consolidated statements of financial position.

NOTE 13 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,304 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan (“RS Plan”) except for the 207 employees of Colowyo Coal. 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 2020, 2019 and 2018 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 $27.5, $25.8 and $27.8 million in 2020, 2019 and 2018, 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 246 bargaining unit employees that are made in accordance with collective bargaining agreements.

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, 2019 and January 1, 2018, 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 currently 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.

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):

	2020	2019
Executive benefit restoration obligation at beginning of period	$ 674	$ —
Service cost	332	116
Interest cost	434	51
Plan amendments - prior service cost	4,674	727
Benefit payments	(715)	—
Actuarial loss (gain)	1,980	(220)
Executive benefit restoration obligation at end of period	$ 7,379	$ 674
Fair value of plan assets at beginning of year	$ —	$ —
Employer contributions	6,955	—
Fair value of plan assets at end of year	$ 6,955	$ —
Net liability recognized	$ 424	$ 674

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. As of December 31, 2020, all trust assets were held in cash and cash equivalents.

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):

	2020	2019
Accumulated other comprehensive loss at beginning of period	$ (130)	$ —
Plan amendments - prior service cost	(4,674)	(220)
Amortization of prior service cost into other income	1,911	84
Unrecognized actuarial (loss) gain	(1,980)	6
Accumulated other comprehensive loss at end of period	$ (4,873)	$ (130)

DEFINED CONTRIBUTION PLAN: We have a qualified savings plan for eligible employees who may make pre-tax and after-tax contributions totaling up to 100 percent of their eligible earnings subject to certain limitations under federal law. We make no contributions for the 246 bargaining unit employees. For all of the eligible non-bargaining unit employees, other than the 225 employees of Colowyo Coal, we contribute 1 percent of an employee's eligible earnings. For the bargaining unit employees of New Horizon Mine, we match 1 percent of employee's contributions. For the employees of Colowyo Coal, we contribute 7 percent of an employee's eligible earnings and also match an employee's contributions up to 5 percent. We made contributions to the plan of $3.5 million, $3.5 million, and $4.6 million in 2020, 2019, and 2018, 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, 2020, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles.

The postretirement medical benefit and postemployment 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):

	2020	2019
Postretirement medical benefit obligation at beginning of period	$ 10,195	$ 8,556
Service cost	601	563
Interest cost	259	352
Benefit payments (net of contributions by participants)	(456)	(617)
Actuarial (gain) loss	(614)	1,341
Postretirement medical benefit obligation at end of period	$ 9,985	$ 10,195
Postemployment medical benefit obligation at end of period	419	375
Total postretirement and postemployment medical obligations at end of period	$ 10,404	$ 10,570

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):

	2020	2019
Amounts included in accumulated other comprehensive income at beginning of period	$ (1,387)	$ 375
Amortization of actuarial (gain) loss into income	—	(342)
Amortization of prior service cost into other income	(68)	(79)
Actuarial gain (loss)	614	(1,341)
Amounts included in accumulated other comprehensive income at end of period	$ (841)	$ (1,387)

The assumptions used in the 2020 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	3.05 %
Initial health care cost trend (2018)	8.00 %
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)	12.72

Changes in the assumed health care cost trend rates would impact the accumulated postretirement medical benefit obligation and the net periodic postretirement medical benefit expense as follows (dollars in thousands):

	1% Increase	1% Decrease
Accumulated postretirement medical benefit obligation	1,233	(1,046)
Net periodic postretirement medical benefit expense	155	(128)

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):

2021	$ 591
2022	603
2023	587
2024	599
2025	590
2025 through 2029	2,945
	$ 5,915

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, 2020	December 31, 2019
Net electric plant	$ 758,273	$ 776,411
Noncontrolling interest	114,852	111,717
Long-term debt	342,355	380,867
Accrued interest	9,942	11,050

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

	2020	2019	2018
Depreciation, amortization and depletion	$ 18,138	$ 18,138	$ 18,138
Interest	22,798	25,320	27,511

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. We also received coal supplies directly from WFA for the Escalante Generating Station in New Mexico. The pricing structure of the coal supply agreements with WFA is 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 $2.4 million at December 31, 2020 and 2019 and is included in investments in other associations.

Western Fuels – Wyoming: WFW, the owner and operator of the Dry Fork Mine in Gillette, Wyoming, was 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 27.13 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, 2020 and 2019 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, 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 2021 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, 2020, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2021	$ 64,637
2022	11,968
2023	7,816
2024	7,361
2025	7,501
Thereafter	142,608
	$ 241,891

Our coal purchases were $101.2 million in 2020, $125.4 million in 2019, and $120.5 million in 2018.

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 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).

As of December 31, 2020, 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):

	2020	2019	2018
Basin	$ 152,461	$ 145,008	$ 149,246
WAPA	72,491	72,504	72,757
Other renewables	69,255	63,677	62,721

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 use and the 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.

GUARANTEES: We provide guarantees under specified agreements or transactions, including certain reclamation obligations of WFW and our subsidiaries. Our guarantees are for payment or performance by us. Most of the guarantees issued by us limit the exposure to a maximum stated amount. During all or part of 2020, we provided guarantees of, or self-bonds for, certain reclamation obligations of WFW and our subsidiaries. We no longer provide guarantees of, or self-bonds for, any reclamation obligations. 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. We no longer have any reclamation obligations associated with Trapper Mine, Dry Fork Mine or Fort Union Mine.

LEGAL:

Transmission Agreement: Pursuant to a long-term transmission agreement with another utility, such utility pays for and has firm rights to transfer power and energy across a transmission path in Colorado. Such right to payment and obligation to provide the transfer is borne equally by us and another entity. Due to the capacity of the transmission path, such utility's firm rights were curtailed. The utility disputed its obligation to pay due to the capacity of the transmission path and claimed we, along with the other entity, breached such transmission agreement. The parties reached a resolution of this matter without us incurring any liability. The resolution of this matter was subject to FERC approval. On October 20, 2020, an unexecuted version of an amended and restated transmission agreement to resolve this matter was filed with FERC for approval. On December 23, 2020, FERC accepted the amended and restated agreement, which resolved this matter.

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. The request was made to FERC to make the new tariffs retroactive to September 3, 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, but did not make the tariffs retroactive to September 3, 2019. However, FERC specifically provided that no refunds are due on our Utility Member rates and our transmission service rates prior to March 26, 2020. FERC did not impose any civil penalties on us. FERC also did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered a 206 proceeding to determine the justness and reasonableness of our rates and wholesale electric service contracts. FERC also rejected our Board Policy 115 ("BP 115") and member project contracts related to our Utility Members' election to provide up to 5 percent of their electric power requirements pursuant to their wholesale electric service contracts on the grounds that the initial filing was incomplete without Board Policy 101 ("BP 101") related to the self-supply in excess of the 5 percent annual allowance. The 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. The settlement proceedings are continuing and settlement offers are being exchanged under the FERC administrative law judge's guidance and in participation with FERC staff. Any refunds to the applicable tariff rates would only apply for sales after March 26, 2020. FERC's March 20, 2020 order regarding our Jurisdictional PDO denied our requested declaration regarding the preemption of the United Power and LPEA proceedings at the COPUC stating they are not currently preempted.

On April 13, 2020, we filed a request for rehearing limited to the issue of preemption of the United Power and LPEA proceedings at the COPUC related to the contract termination payment amount as described in our Jurisdictional PDO. Requests for rehearing related to both the Jurisdictional PDO and tariff filings were filed with FERC by other parties, including United Power. 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. The August 28 Order also set aside requests for rehearing filed with FERC by other parties related to the Jurisdictional PDO. Requests for rehearing related to FERC's August 28 Order were filed with FERC by United Power and LPEA. On October 28, 2020, FERC issued an order denying the requests for rehearing filed by United Power and LPEA.

On July 1, 2020, we re-submitted our BP 101, BP 115, and all existing member project contracts with FERC for acceptance and on August 28, 2020 FERC accepted the filings effective August 31, 2020. FERC also ordered a 206 proceeding to determine whether our July 1 filed documents are just and reasonable and set them for settlement and hearing procedures, which were consolidated with the ongoing settlement and hearing procedures in effect for our Utility Members rates docket. FERC also established a refund effective date related to our July 1 filed documents of September 1, 2020. A request for rehearing related to this FERC order was filed with FERC by United Power. In November 2020, FERC issued an order addressing the arguments for rehearing raised by United Power and modified its August 28, 2020 order with the same result in the proceeding. United Power has 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 acceptance of our July 1 filed documents and such matter is being held in abeyance pending resolution of the Jurisdictional PDO appeal discussed below.

On July 13, 2020, we filed a petition for review with the D.C. Circuit Court of Appeals to protect our interest, and requested review of FERC's order granting in part and denying in part our Jurisdictional PDO and FERC's order granting rehearings for further consideration. 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, including United Power. On September 18, 2020, FERC filed to hold the appeals in abeyance. On September 29, 2020, an order was issued considering the motion to hold the case in abeyance directing the parties to file motions to govern future proceedings by January 11, 2021. FERC, United Power, and the other parties reached agreement on the procedures and schedule for the Jurisdictional PDO and abeyance on all non-Jurisdictional PDO matters and such filing was made to the D.C. Circuit Court of Appeals.

It is not possible to predict if FERC will require us to refund amounts to our customers for sales after March 26, 2020, if FERC will approve our current practices regarding use of regulatory assets are just and reasonable, or to estimate any liability associated with these matters. In addition, we cannot predict the outcome of the 206 proceedings or 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. We filed a response on September 29, 2020. 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 November 25, 2020, LPEA and United Power jointly filed an application for rehearing, reargument, and reconsideration with the COPUC of its October 22, 2020 decision. The COPUC denied LPEA's and United Power's November 25 application, which denial became final on December 28, 2020. 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's Adams District Court Complaints: On May 4, 2020, United Power filed a Complaint for Declaratory Judgement and Damages in the Adams County District Court, 2020CV30649, against us and our three Non-Utility Members 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 a “Make-Whole” methodology for 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 a “Make-Whole” methodology for 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. United Power filed its response on July 30, 2020. 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 the claims from its November 2020 complaint, discussed below, into its amended complaint and to dismiss the November 2020 complaint against us. The court has not yet decided whether United Power will be granted leave to file its amended complaint.

In addition, on November 23, 2020, United Power filed a Complaint for Declaratory Relief in the Adams County District Court, 2020CV031496, against us seeking for the court to declare that our addition of the Non-Utility Members violated Colorado law. On December 11, 2020, we moved to dismiss United Power's November 2020 compliant because it repeats the claims pending in the May 2020 complaint proceeding. The court has not yet ruled on our motion. It is not possible to predict the outcome of these matters or whether we will incur any liability in connection with these matters.

NOTE 16 – QUARTERLY FINANCIAL DATA (UNAUDITED)

Unaudited operating results by quarter for 2020 and 2019 are presented below. Results for the interim periods may fluctuate as a result of seasonal weather conditions, changes in rates and other factors. In the opinion of management, all adjustments (consisting of normal recurring accruals) necessary for the fair statement of our results of operations for such periods have been included (dollars in thousands):

Statement of Operations Data	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2020					
Operating revenues	$ 319,466	$ 313,656	$ 401,601	$ 317,572	$ 1,352,295
Operating margins	28,998	41,605	79,970	7,087	157,660
Net margins attributable to the Association	(4,610)	5,433	44,829	(20,531) (1)	25,121
2019					
Operating revenues	$ 339,917	$ 314,588	$ 399,053	$ 331,914	$ 1,385,472
Operating margins	40,517	34,945	77,347	13,616	166,425
Net margins attributable to the Association	6,989	(1,385)	55,145	(15,440) (2)	45,309

(1) In the fourth quarter of 2020, we recognized $12.1 million of previously deferred non-member electric sales revenue.
(2) In the fourth quarter of 2019, we recognized $6.2 million of previously deferred non-member electric sales revenue.

NOTE 17 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 5, 2021, which is the date when the financial statements were issued.

As part of our decommissioning of the Escalante Generating Station and in order for McKinley Paper Company to continue its operations, McKinley Paper Company has exercised certain options under prior agreements to purchase certain of our property and retain easements for certain other property and we have agreed to sell certain additional property and provide certain additional easements to McKinley Paper Company. As of December 31, 2020, assets related to the sale were classified as electric plant held for sale on our consolidated statements of financial position. The sale of property closed on January 28, 2021.

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, 2020 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, 2020. 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, 2020.

Changes in Internal Control over Financial Reporting

There were no changes that occurred during the fourth quarter ended December 31, 2020 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, 2021 are as follows:

NAME	AGE	UTILITY MEMBER - REPRESENTATIVE
Rick Gordon—Chairman and President	67	Mountain View Electric Association, Inc.
Timothy Rabon—Vice Chairman	60	Otero County Electric Cooperative, Inc.
Julie Kilty—Secretary	62	Wyrulec Company
Stuart Morgan—Treasurer	74	Wheat Belt Public Power District
Matt M. Brown—Assistant Secretary	69	High Plains Power, Inc.
Scott Wolfe—Assistant Secretary	57	San Luis Valley Rural Electric Cooperative, Inc.
Arthur W. Connell—Executive Committee	67	Central New Mexico Electric Cooperative, Inc.
Donald Keairns—Executive Committee	61	San Isabel Electric Association, Inc.
Douglas Shawn Turner—Executive Committee	59	The Midwest Electric Cooperative Corporation
Charles Abel	52	Sangre de Cristo Electric Association, Inc.
Leroy Anaya	64	Socorro Electric Cooperative, Inc.
Robert Baca	56	Mora-San Miguel Electric Cooperative, Inc.
Lucas Bear	40	Northwest Rural Public Power District
Robert Bledsoe	71	K.C. Electric Association
Lawrence Brase	74	Southeast Colorado Power Association
Leo Brekel	69	Highline Electric Association
William Bridges	60	Big Horn Rural Electric Company
Jerry Burnett	74	High West Energy, Inc.
Kevin Cooney	65	San Miguel Power Association, Inc.
Lucas Cordova Jr.	55	Jemez Mountains Electric Cooperative, Inc.
Mark Daily	68	Gunnison County Electric Association, Inc.
Jerry Fetterman	65	Empire Electric Association, Inc.
John "Jack" Finnerty	81	Wheatland Rural Electric Association
Joel Gilbert	62	Southwestern Electric Cooperative, Inc.
Randy Graff	66	Morgan County Rural Electric Association
Ronald Hilkey	81	White River Electric Association, Inc.
Ralph Hilyard	82	Roosevelt Public Power District
Hal Keeler	92	Columbus Electric Cooperative, Inc.
Brian McCormick	45	United Power, Inc.
Kohler McInnis	66	La Plata Electric Association, Inc.
Thaine Michie	80	Poudre Valley Rural Electric Association, Inc.
Stanley Propp	74	Chimney Rock Public Power District
Steve M. Rendon	66	Northern Rio Arriba Electric Cooperative, Inc.
Claudio Romero	74	Continental Divide Electric Cooperative, Inc.
Peggy A. Ruble	67	Garland Light & Power Company
Roger Schenk	57	Y-W Electric Association, Inc.

Gary Shaw	66	Springer Electric Cooperative, Inc.
Darryl Sullivan	70	Sierra Electric Cooperative, Inc.
Clay Thompson	62	Carbon Power & Light, Inc.
Carl Trick II	73	Mountain Parks Electric, Inc.
William Wilson	66	Niobrara Electric Association, Inc.
Phillip Zochol	45	Panhandle Rural Electric Membership Association

Rick Gordon has served on our Board since November 1994 and is Chairman and President 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. 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.

Timothy Rabon has served on our Board since April 2014 and is Vice Chairman of the Board. He is a member of the Executive Committee and serves as Chairman of the Engineering and Operations 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.

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 Finance and Audit 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.

Donald Keairns has served on our Board since April 2012. 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.

Douglas Shawn Turner has served on our Board since April 2015. He is a member of the Executive Committee and 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 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 works for 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 Vice 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 owns and operates Brase Insurance Agency, 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 Coone*y 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.

Lucas Cordova Jr. has served on our Board since August 2013. He is a member of the Engineering and Operations Committee. Mr. Cordova serves as a trustee of Jemez Mountains Electric Cooperative, Inc. He is also the owner of Aspen Tree and Crane Service, LLC.

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.

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.

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.

Thaine Michie has served on our Board since March 2009. He 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.

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 works for 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, 2021:

NAME	AGE	POSITION
Duane Highley	59	Chief Executive Officer
Joel Bladow	61	Senior Vice President, Transmission
Patrick L. Bridges	62	Senior Vice President/Chief Financial Officer
Jennifer Goss	51	Senior Vice President, Chief Technology Officer and Member Relations
Barry Ingold	57	Senior Vice President, Generation
Bradford Nebergall	62	Senior Vice President, Energy Management
Kenneth V. Reif	69	Senior Vice President, General Counsel
Barbara Walz	58	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 38 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 39 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 38 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.

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 associated with the retirement of Ellen Conner 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 22 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 23 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 34 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 41 years of utility experience.

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 24 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 executed retention agreements for certain executive officers and other staff as deemed appropriate from time to time.

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 employees as well as certain employees of one of our subsidiaries, Elk Ridge, working at the New Horizon Mine. 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.

We offer one 401(k) plan to all employees of Elk Ridge working at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions.

We offer one 401(k) plan to employees of Elk Ridge working at the New Horizon Mine and contribute 1 percent of employee base salary for all employees.

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. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees currently 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.

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: the Chief Executive Officer and other executive officers are provided a company vehicle for both business and personal use. There are no restrictions on usage. These vehicles are considered compensation, which is 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:

Rick Gordon
Timothy Rabon
Julie Kilty
Stuart Morgan
Matt M. Brown
Scott Wolfe
Arthur W. Connell
Donald Keairns
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. Rick Gordon, Timothy Rabon, Julie Kilty, Stuart Morgan, Matt M. Brown, Scott Wolfe, Arthur W. Connell, Donald Keairns 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. Gordon is our Chairman and President, Mr. Rabon 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 2020.

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 2020). 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)	2020	$ 1,350,000	$ 2,076,328	$ 49,596	$ 3,475,924
Chief Executive Officer	2019	1,043,482	877,155	121,078	2,041,715
Patrick L. Bridges	2020	496,884	463,739	162,430	1,123,053
Senior VP/CFO	2019	445,209	105,878	50,194	601,281
	2018	431,081	351,082	47,608	829,771
Barbara Walz	2020	367,427	591,192	117,246	1,075,865
Senior VP, Policy and	2019	326,090	36,563	37,926	400,579
Compliance/CCO	2018	315,741	292,206	35,448	643,395
Bradford Nebergall	2020	438,381	400,567	153,542	992,490
Senior VP, Energy	2019	407,506	98,391	51,624	557,521
Management	2018	394,951	267,508	45,622	708,081
Barry Ingold	2020	450,400	517,490	120,413	1,088,303
Senior VP, Generation	2019	369,677	136,107	27,493	533,277
	2018	358,494	304,013	23,790	686,297

(1) Includes 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.

Retention Agreements

We had retention agreements with certain executive officers including the following named executive officers: 1) Senior Vice President/Chief Financial Officer, 2) Senior Vice President, Energy Management, 3) Senior Vice President, Generation, and 4) Senior Vice President, Policy and Compliance/Chief Compliance Officer.

The retention agreements were made effective June 27, 2018 and ended on June 1, 2020. In consideration of the above mentioned executives continuing employment during such period, the executives received a retention payment in June 2020 in the amount agreed to in the agreement as follows:

Executive Title	Retention Payment
Senior Vice President/Chief Financial Officer	$ 107,130
Senior Vice President, Energy Management	98,150
Senior Vice President, Generation	89,091
Senior Vice President, Policy and Compliance/Chief Compliance Officer	78,468

The retention agreements were not employment agreements and did not guarantee the executive the right to continue in the employment of us or our subsidiaries.

Defined Benefit Plan

The following table lists the estimated values under the RS Plan and both restoration plans as of December 31, 2020. As a result of changes in Internal Revenue Service regulations, the annual base salary used in determining benefits is limited to $285,000 effective January 1, 2020.

Name	Number of years Credited Service a of December 31, 2020	RS Plan Present Value of Accumulated Benefit as of December 31, 2020	Pension Restoration Plans Present Value of Accumulated Benefit as of December 31, 2020	Payments During 2020
Duane D. Highley (1)	1 year, 9 months	$ 2,598,121	$ 2,552,427	None
Patrick L. Bridges	13 years, 3 months	1,311,997	737,767	None
Barbara Walz	23 years, 1 month	2,055,410	281,740	None
Bradford Nebergall	12 years, 3 months	1,212,278	521,165	None
Barry Ingold	16 years, 0 months	1,361,844	404,626	None

(1) Mr. Highley began employment with us on April 1, 2019. He has 1 years 9 months of service with us and a total of 36 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.

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, 2020.

Chief Executive Officer Pay Ratio

The 2020 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	2020 Total Compensation (1)
Median annual total compensation of all employees (excluding Chief Executive Officer)	$ 162,468
Annual Total Compensation of Duane D. Highley, Chief Executive Officer	3,475,924
Ratio of the median annual total compensation of all employees to the annual total compensation of Duane D. Highley, Chief Executive Officer	1.0:21.4

(1) Includes change in pension value from 2019 to 2020.

In determining the median employee, a listing was prepared of all active employees of us and our subsidiaries as of December 31, 2020. 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 2020. We determined the compensation of our median employee by (1) utilizing the W-2 Box 5 wages for all active employees for 2020 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, it was determined there was no material difference and we did not change the median employee.

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. 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.

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 paid to the Board in 2020 for services rendered. Director fees are paid after submission of receipts to us. Amounts in the table reflect actual payments made in 2020. Directors are also reimbursed for expenses as described above.

Name	2020 Board Fees(1)
Charles Abel	$ 14,500
Leroy Anaya	19,000
Robert Baca	23,000
Lucas Bear	6,000
Robert Bledsoe	24,000
Lawrence Brase	23,000
Leo Brekel	9,750
William Bridges	8,500
Matt M. Brown	17,500
Jerry Burnett	14,500
Richard Clifton(3)	13,000
Arthur W. Connell	32,500
Kevin Cooney	8,500
Lucas Cordova Jr.	20,500
Mark Daily	14,250
Tim Erickson(3)	2,000
Jerome Fetterman	3,000
John "Jack" Finnerty	19,500
Gary Fuchser(3)	8,000
Joel Gilbert	17,000
Rick Gordon (2)	167,691
Randolph Graff	10,500
Ronald Hilkey	14,500
Ralph Hilyard	11,500
Donald Keairns	23,500
Hal Keeler	16,500
Richard Kildow	2,000
Julie Kilty	36,500
Kyle S. Martinez(3)	8,500
Brian McCormick	14,500
Kohler McInnis	3,700
Thaine Michie	21,000
William Mollenkopf(3)	19,500
Stuart Morgan	26,500
Stanley Propp	14,000
Timothy Rabon	26,750
Steve Rendon	17,500
Claudio Romero	14,500

Peggy Ruble	16,500
Donald Russell(3)	11,500
Roger Schenk	16,000
Brian Schlagel(3)	9,500
Gary Shaw	15,000
Jack Sibold(3)	7,500
Kirsten Skeehan(3)	7,000
Darryl Sullivan	11,200
N. Clay Thompson	5,000
Carl Trick II	14,500
William Wilson	15,500
Scott Wolfe	30,500
Phillip Zochol	7,250

(1) Various directors have deferred a total of $42,850 of the actual Board fee payments made in 2020. Some directors deferred up to 100 percent of their fee payments.

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

(3) Individual ceased serving on the Board prior to December 31, 2020.

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 2020.

In 2020, certain of our directors served on the board of directors of other entities in which we have or had ownership interests, including Trapper Mining. We purchased coal for the Yampa Project from Trapper Mining of $20.2 million in 2020.

Other than as described above, in 2020, 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.

	2020	2019
Audit Fees(1)	$ 821,000	$ 813,000
Audit-Related Fees(2)	—	—
Tax Fees(3)	51,000	55,000
All Other Fees(4)	—	—
Total	$ 872,000	$ 868,000

(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 2019 and 2020.
(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 pre-approved by the Finance and Audit Committee. In the event that time does not allow for Finance and Audit Committee 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. Pre-approval is granted usually at regularly scheduled meetings. During 2020 and 2019, all services performed by Ernst & Young LLP were pre-approved by the Finance and Audit Committee or pre-approved by both the Chairman and the Vice-Chairman of the Finance and Audit Committee 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.
3.2	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc.
4.1†	Indenture, dated effective as of December 15, 1999, between Tri-State Generation and Transmission Association, Inc. and Wells Fargo 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 Wells Fargo 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 Wells Fargo 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 Wells Fargo 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 Wells Fargo 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 Wells Fargo 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 Wells Fargo, in the original amount of $46,800,000 related to Pollution Control Refunding Revenue Bonds, Series 2009B.
4.18.1*	Notes, dated April 8, 2009, from Tri-State to various purchasers, relating to Series 2009C Note Purchase Agreement
4.18.2*	Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement
4.18.3*	Notes, dated December 12, 2017, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement
4.18.4*	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.)
10.4†	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, Wells Fargo Delaware Trust Company, as 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 Wells Fargo Bank, National Association, as 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 Wells Fargo Bank, National Association, as 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†	Series 2009C Note Purchase Agreement, dated as of April 8, 2009, between Tri-State and various purchasers of the notes identified therein (Filed as Exhibit 10.7 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.8†	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.)
10.9†	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.)
10.10†	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.)
10.11**†	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.)
10.12**	Executive Benefit Restoration Plan, dated December 12, 2014, as amended by Amendment effective July 30, 2020
10.13**†	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 5, 2021

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 5, 2021
/s/ PATRICK L. BRIDGES Patrick L. Bridges	Senior Vice President/Chief Financial Officer (principal financial officer)	March 5, 2021
/s/ DENNIS J. HRUBY Dennis J. Hruby	Senior Manager Controller (principal accounting officer)	March 5, 2021
/s/ RICK GORDON Rick Gordon	Chairman, President and Director	March 5, 2021
/s/ TIMOTHY RABON Timothy Rabon	Director	March 5, 2021
/s/ JULIE KILTY Julie Kilty	Director	March 5, 2021
/s/ STUART MORGAN Stuart Morgan	Director	March 5, 2021
/s/ MATT M. BROWN Matt M. Brown	Director	March 5, 2021
/s/ SCOTT WOLFE Scott Wolfe	Director	March 5, 2021
/s/ ARTHUR W. CONNELL Arthur W. Connell	Director	March 5, 2021
/s/ DONALD KEAIRNS Donald Keairns	Director	March 5, 2021
/s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	March 5, 2021
/s/ CHARLES ABEL Charles Abel	Director	March 5, 2021
/s/ LEROY ANAYA Leroy Anaya	Director	March 5, 2021
/s/ ROBERT BACA Robert Baca	Director	March 5, 2021

/s/ LUCAS BEAR Lucas Bear	Director	March 5, 2021
/s/ ROBERT BLEDSOE Robert Bledsoe	Director	March 5, 2021
/s/ LAWRENCE BRASE Lawrence Brase	Director	March 5, 2021
/s/ LEO BREKEL Leo Brekel	Director	March 5, 2021
/s/ WILLIAM BRIDGES William Bridges	Director	March 5, 2021
/s/ JERRY BURNETT Jerry Burnett	Director	March 5, 2021
/s/ KEVIN COONEY Kevin Cooney	Director	March 5, 2021
/s/ LUCAS CORDOVA JR. Lucas Cordova, Jr.	Director	March 5, 2021
/s/ MARK DAILY Mark Daily	Director	March 5, 2021
/s/ JERRY FETTERMAN Jerry Fetterman	Director	March 5, 2021
/s/ JOHN FINNERTY John Finnerty	Director	March 5, 2021
/s/ JOEL GILBERT Joel Gilbert	Director	March 5, 2021
/s/ RANDOLPH GRAFF Randolph Graff	Director	March 5, 2021
/s/ RONALD HILKEY Ronald Hilkey	Director	March 5, 2021
/s/ RALPH HILYARD Ralph Hilyard	Director	March 5, 2021
/s/ HAL KEELER Hal Keeler	Director	March 5, 2021
/s/ BRIAN MCCORMICK Brian McCormick	Director	March 5, 2021
/s/ KOHLER MCINNIS Kohler McInnis	Director	March 5, 2021
/s/ THAINE MICHIE Thaine Michie	Director	March 5, 2021
/s/ STANLEY PROPP Stanley Propp	Director	March 5, 2021
/s/ STEVE M. RENDON Steve M. Rendon	Director	March 5, 2021

Claudio Romero	Director	
/s/ PEGGY A. RUBLE Peggy A. Ruble	Director	March 5, 2021
/s/ ROGER SCHENK Roger Schenk	Director	March 5, 2021
/s/ GARY SHAW Gary Shaw	Director	March 5, 2021
/s/ DARRYL SULLIVAN Darryl Sullivan	Director	March 5, 2021
/s/ CLAY THOMPSON Clay Thompson	Director	March 5, 2021
/s/ CARL TRICK II Carl Trick II	Director	March 5, 2021
/s/ WILLIAM WILSON William Wilson	Director	March 5, 2021
/s/ PHILLIP ZOCHOL Phillip Zochol	Director	March 5, 2021