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, 2019

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 (State or other jurisdiction of incorporation or organization)	**84-0464189** (I.R.S. employer identification number)
1100 West 116th Avenue **Westminster, Colorado** (Address of principal executive offices)	**80234** (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 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 AN D 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
BART	best available retrofit technology
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
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
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 electric distribution member systems
Moody's	Moody's Investors Services, Inc.
MRO	Midwestern Reliability Organization
MRRE	Multi-Regional Registered Entity
MW	Megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission

NO_X	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NRECA	National Rural Electric Cooperative Association
NSPS	New Source Performance Standard
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
PVREA	Poudre Valley Rural Electric Association, Inc.
RCRA	Resource Conservation and Recovery Act, 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
Sunflower	Sunflower Electric Power Corporation
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.
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.
WIIN	Water Infrastructure Improvements for the Nation
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 serving large portions of Colorado, Nebraska, New Mexico and Wyoming. We were incorporated under the laws of the State of Colorado in 1952 as a cooperative corporation. We supply wholesale electric power to our forty-three Members, which, in turn, supply retail electric power to residential, commercial, industrial and agricultural customers.

We are owned entirely by our forty-six members. Thirty-nine 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 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 Members serve approximately 624,000 retail electric meters. Our Members are the sole state certified providers of electric service to retail (residential and business) customers within their designated service territories.

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.

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.

Including our subsidiaries, as of December 31, 2019, we employed 1,467 people, of which 280 were subject to collective bargaining agreements. As of December 31, 2019, none of these collective bargaining agreements will expire within one year. We expect the number of employees to decrease materially by 2030 with the closure of certain of our generating facilities and a coal mine by 2030.

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.

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 Member flexibility, all with a goal to lower wholesale rates to our Members. In January 2020, we announced the actions of our Responsible Energy Plan, which will advance our cleaner generation portfolio and programs to serve our Members. Some of the actions of the Responsible Energy Plan include:

- Reducing emissions by eliminating 100 percent of emissions from our New Mexico coal-fired generating facilities by the end of 2020 and from our Colorado coal-fired generating facilities by 2030.
- Increasing clean energy by bringing over 1 gigawatt of wind and solar resources online by 2024, meaning 50 percent of the energy consumed by our Members' customers is expected to come from renewable sources by 2024.
- Increasing Member flexibility to develop more local, self-supplied renewable energy.
- Extending benefits of a clean grid across the economy through expanded electric vehicle infrastructure and beneficial electrification.

Power Supply and Transmission

We supply and transmit our 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 January 1, 2020, our diverse generation portfolio provides us with maximum available power of 4,317 MWs and is summarized in the table below:

Generation Portfolio (as of January 1, 2020)	**Capacity (MW)**	**Percentage (%)**
Coal-fired base load facilities	1,782	41
Renewables-contracts, including WAPA	1,059	25
Gas/oil-fired facilities	903	21
Other contracts, including Basin	573	13

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 615 MWs. In January 2020, we also announced the early retirements of Craig Station by 2030 and Escalante Station by the end of 2020. 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.

After the retirement of Escalante Station and the addition of new renewable generating facilities, as of January 1, 2025, we anticipate our generation portfolio to be the following:

Generation Portfolio (as of January 1, 2025)	**Capacity (MW)**	**Percentage (%)**
Coal-fired base load facilities	1,529	30
Renewables-contracts, including WAPA	2,070	41
Gas/oil-fired facilities	903	18
Other contracts, including Basin	573	11

In addition to our diverse generation portfolio, as permitted by our wholesale electric service contracts with our Members, as of December 31, 2019, our Members own or control through long-term purchase power contracts approximately 123 MWs of operating distributed or renewable capacity that is used to deliver energy to our Members' customers.

We transmit power to our 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 5,671 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 407 substations and switchyards. See “PROPERTIES” for a description of our transmission facilities.

MEMBERS

General

We have two classes of members - all requirements electric members known as our Members or Class A members and non-utility members. Our 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 Members’ businesses involve the operation of substations, transformers and electric lines that deliver power to their customers. We currently have 43 Members. Our Members and their locations are as follows:

Colorado:

Delta-Montrose Electric Association	Poudre Valley Rural Electric Association, Inc.
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, Inc.	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.

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 3 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 Member, unless otherwise specified in a written agreement, to purchase all electric power and energy used by the Member from us. This requirement in our Bylaws is further specified in the wholesale electric service contract with each Member, which is an all-requirements contract. Each wholesale electric service contract obligates us to sell and deliver to the Member, and obligates the Member to purchase and receive, at least 95 percent of its electric power requirements from us.

At the 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. 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 no representation on our Board. We currently have 3 non-utility members. We may add new members in the future.

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, including all obligations under its wholesale electric service contract with us. From time to time, a 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 Members equitable terms and conditions for withdrawal. In addition, from time to time, we may be in discussions with a Member regarding the equitable terms and conditions for withdrawal and their request for withdrawal, including granting a 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 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 withdrawal from membership in us is as provided in their respective membership agreement.

Wholesale Electric Service Contracts

Our revenues are derived primarily from the sale of electric power to our Members pursuant to long-term wholesale electric service contracts. We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members (which constituted approximately 96.8 percent of our revenue from Member sales in 2019) and extending through 2040 for the remaining Member (DMEA).

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 Member, and obligates the 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 Member’s distribution or transmission system. Each Member may elect to provide up to 5 percent of its requirements from distributed or renewable generation owned or controlled by the Member. As of December 31, 2019, 21 Members have enrolled in this program with capacity totaling approximately 136 MWs of which 123 MWs are in operation. In 2019, we estimate that nearly a third of the energy delivered by us and our Members to our Members’ customers came from non-carbon emitting resources. See also “— MEMBERS – Contract Committee” for a description of our community solar program for our Members.

Our 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 Members' aggregate coincident peak demand for the years 2015 through 2019 and the amount of energy that we supplied them. Our Members' peak demand and our annual amount of energy sold to our Members for 2019 increased by 1.2 percent and 0.2 percent, respectively, compared to 2018.

Year	Members' Peak Demand (MW) (1)	Amount of Energy Sold (MWh) (1)
2019	3,009	16,412,525
2018	2,974	16,384,415
2017	2,850	15,905,656
2016	2,802	15,746,382
2015	2,753	15,780,670

(1) Includes peak demand of and energy sales to 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 Members. If our generation and sources of supply are inadequate to serve all of our Members' demand, and we are unable to secure additional sources of supply, we are permitted to interrupt service to our Members in accordance with a written policy established by our Board. We are currently able to provide all the requirements of our 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 Members provide that our 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 Members are obligated to pay us monthly for the power, energy and transmission service we supply to them. Revenue from one Member, United Power, comprised 16.6 percent of our Member revenue and 14.8 percent of our operating revenue in 2019. No other Member exceeded 10 percent of our Member revenue or our operating revenue in 2019. Payments due to us under the wholesale electric service contracts are pledged and assigned to secure the obligations secured under our Master Indenture. A 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 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 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. In February 2016, we filed a Petition for Declaratory Order with FERC for a clarification that the fixed cost recovery mechanism in our revised Board policy is consistent with the provisions of PURPA and the implementing regulations of FERC. The revised Board policy provides for recovery of the unrecovered fixed costs directly from that Member, rather than allocating the costs among all of our Members. The fixed cost recovery is calculated based on the difference between our wholesale rate to our Members and our avoided costs. In June 2016, FERC denied our Petition for Declaratory Order related to the fixed cost recovery mechanism in our revised Board policy. We filed a Request for Rehearing with FERC regarding FERC's June 2016 order. We are awaiting FERC's decision on our request for rehearing. See "LEGAL PROCEEDINGS."

In July 2016, we filed on behalf of ourselves and thirty of our Members 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 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 Members will sell supplementary, back-up, and maintenance power to the qualifying facilities. We are awaiting FERC's decision on this petition for waiver.

Contract Committee

The wholesale electric service contracts we have with our 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 2016 and 2017, a contract committee consisting of a representative from each Member discussed changes to the wholesale electric service contracts. The contract committee in 2017 recommended to our Board no changes to the wholesale electric service contracts with our Members, but did recommend that the contract committee be reconvened in 2 years. In 2019, the contract committee consisting of a representative from each Member reconvened to review the wholesale electric service contracts and discuss changes, including alternative contracts with our Members.

The contract committee has regularly met since it convened in 2019 to discuss alternative contracts for our Members, including partial requirements contracts. As part of the contract committee considering alternative contracts with our Members, including partial requirements contracts, and the interaction with shopping letters and the withdrawal number for a Member to meet all its contractual obligations to us, at our September 2019 Board meeting, our Board approved a temporary suspension of the policy and practice of providing its Members with withdrawal numbers and shopping letters. The suspension is expected to continue until the contract committee has completed its work and provided recommendations to our Board, our Board has had an opportunity to consider and act upon such recommendations, and our Board has fully assessed the financial impacts of Member withdrawals and/or the offering of alternative contracts. At our September 2019 Board meeting, our Board also authorized the contract committee to consider alternative methods to determine the withdrawal number with a goal of completing such work and presenting it to our Board by April 2020.

In November 2019, the contract committee recommended to the Board and the Board approved a community solar garden program, which is in addition to the 5 percent self-supply provision of the wholesale electric service contracts. Each Member is eligible for community solar garden projects up to, in aggregate, the lesser of 4.6 million kWhs or 2 percent of such Member's 2018 energy sales from us. The community solar garden program, if acted upon by all Members, would be approximately 63 MWs of community solar projects. In February 2020, the contract committee recommended to the Board and the Board announced a commitment to provide our Members with the option of entering into a partial requirements contract. The partial requirements option is subject to further refinement, but is expected to include holding an open season for Members to choose to enter into a partial requirements contract and the open season would permit Members collectively to self-supply up to 300 MWs, approximately 10 percent of our Members' peak demand. The 300 MWs is in addition to the 5 percent self-supply provision of the wholesale electric service contracts and the community solar garden program. In addition, additional open seasons could be offered in the future and Members that choose the partial requirements option will make other Members financially whole through a buy-down payment or payments. The Board further directed the contract committee to make recommendations to the Board on the specific details for the partial requirements contracts, including the partial requirements buy-down number methodology and the process for implementing the offering.

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 Member flexibility, all with a goal to lower wholesale rates to our 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.

In January 2020, we announced our Responsible Energy Plan, which will rapidly advance our transition to a cleaner generation portfolio and offer new programs to serve our Members. The plan, which was developed with input from our Board, our Members and external stakeholders, includes the following elements:

- Retirement of Coal Generation – Retirement of Escalante Station by the end of 2020 and Craig Station by 2030. In addition, the Colowyo Mine will cease coal production operations by 2030. The retirements are expected to result in greenhouse gas emission reductions of 90 percent from generation we own or operate in Colorado and 70 percent from Colorado wholesale electric sales relative to 2005 levels.

- Increase renewable energy – We will pursue six new renewable energy projects in Colorado and New Mexico, which along with two projects previously announced in early 2019, is expected to result in more than 1 gigawatt of additional renewable resources being added to our generation portfolio by 2024, meaning 50 percent of the energy consumed by our Members' customers is expected to come from renewables by 2024.
- New beneficial electrification, energy efficiency and demand side management programs – Committing to expanding programs to help our Members' rural consumers save money and energy while cutting emissions through use of electric vehicles, energy efficiency, beneficial electrification and other initiatives.
- Employee Support – For our employees at Escalante Station, we will offer several options, including: severance packages for all employees, the option to apply for other positions with us, assistance with financial planning, educational assistance and supplemental funding to help employees pay for health benefits. In Colorado, where we have more time, we will work to negotiate a specific severance package for employees with their union and begin working with employees.
- Community support – Our Board approved a $5 million financial package and a community reinvestment package, including the power purchase contract for a new solar project near Escalante Station. In Colorado, we have committed to working with community members to develop and begin to implement economic development, retraining and other strategies to ease the transition in the near future.

When we announced the Responsible Energy Plan, we also identified several challenges we need to work with others to address to ensure a cost-effective, efficient and equitable transition, including:

- Community concerns – Identifying dedicated and meaningful support for transitioning communities, so communities that lose employment, tax and royalty payments, and other benefits associated with existing generation and production facilities do not have to carry the weight of the transition alone.
- Stranded assets – We will need to work with policymakers to address the treatment for cooperative debt and stranded assets, so cooperative associations can retire coal-fired generation and add renewables in accordance with state regulations while reducing upward rate pressure.
- Regional Transmission Organization – We will need to participate in a regional transmission organization in the near future in order to be able to ensure electricity reliability and affordability while transitioning to a clean grid in a cost-effective and efficient manner.
- Infrastructure siting – Find ways to streamline siting and permitting for necessary infrastructure, to be able to build transmission and generation infrastructure that meets the time and cost expectations of the clean energy transition.

Members' Service Territories and Customers

Service Territories. Our 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 Members have exclusive rights to provide electric service to retail customers within designated service territories. In Colorado, our Members' service territories extend throughout the state and encompass suburban, rural, industrial, agricultural and mining areas. In Nebraska, our Members' service territories are comprised primarily of rural residential and farm customers in the western part of the state. In New Mexico, our 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 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 Members' service territories creates diversity within our system.

Customers. According to information we received from our Members, our Members' sales of energy in 2018 (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	29.3 %	82.8 %
Large commercial	38.6	0.1
Small commercial	22.0	12.8
Irrigation	7.4	3.9
Other	2.7	0.4

From 2014 to 2018, our Members experienced an average annual compound growth rate of approximately 1.4 percent in the number of customers and an average annual compound growth rate of 2.3 percent in energy sales. In 2018, which is the most recent year with data available to us, the 15 largest customers of our Members represented 17.4 percent of electric energy sales by our Members, although no single customer of our 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 Members' average number of customers per mile of energized line is approximately five customers per mile. System densities of our Members in 2018 ranged from 1.2 customers per mile to 13.9 customers per mile.

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 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, including all obligations under its wholesale electric service contract with us.

DMEA requested an exit cost calculation from us and we provided to DMEA a preliminary buyout number. DMEA disputed the buyout number provided to DMEA by us and filed a formal complaint with the COPUC in December 2018 alleging that the COPUC had jurisdiction over the equitable terms and conditions as our Board may prescribe for withdrawal. In July 2019, we reached a settlement with DMEA that provides 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 amount of the withdrawal payment was the product of the negotiated settlement with DMEA and is unique to DMEA because of the amounts associated with the transmission assets being transferred and patronage capital, and the date of withdrawal of DMEA from us. The specific terms of the settlement will be set forth in a withdrawal agreement, which will be subject to receipt of certain approvals and other conditions. The settlement agreement provides for the parties to cooperate to complete DMEA's withdrawal effective May 1, 2020, but we expect the withdrawal effective date to occur at a later date agreed to by the parties.

In November 2019, LPEA filed a formal complaint with the COPUC alleging that we have hindered LPEA's ability to seek withdrawal from us. LPEA alleges, among other things, that our Board's temporary suspension of providing Members with withdrawal numbers is unlawful. LPEA seeks for the COPUC to issue an order related to our temporary suspension and for the COPUC to establish the withdrawal number. In November 2019, United Power filed a formal complaint with the COPUC alleging that we have hindered United's ability to explore its power supply options by either withdrawing from us or continuing as a member under a partial requirements contract. United Power alleges, among other things, that we have failed to provide a just, reasonable, and non-discriminatory withdrawal number. United Power seeks for the COPUC to issue an order establishing a withdrawal number. The COPUC has consolidated the proceeding. A five-day evidentiary hearing is scheduled to begin on March 23, 2020. See "LEGAL PROCEEDINGS."

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 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 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 Members' load in the Eastern Interconnection. See "— POWER SUPPLY RESOURCES — Purchased Power."

Competition

In accordance with state regulations, our Members have exclusive rights to provide electric service to retail customers within designated service territories. States in which our Members' service territories are located have not enacted retail competition legislation. Federal legislation could mandate retail choice in every state. Our 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 Members' systems. Our Members are also subject to competition for attracting new loads as potential customers may locate their facilities in our 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 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 Members are subject to competition from third party energy remarketing companies. Energy remarketing companies are targeting our Members and the communities our Members serve by claiming to be able to offer lower priced and cleaner wholesale electric power. This includes assisting our Members in seeking to withdrawal from membership in us and financing the withdrawal number payable by our Members. It also includes assisting some municipalities that our Members serve by helping them create electric utilities.

RATE REGULATION

New Developments

At our July 2019 Board meeting, because of increased pressure by the states to regulate our rates and charges, our Board authorized us to take action to place us under wholesale rate regulation by FERC. In connection with such authorization, our Board, in accordance with our Bylaws, established a non-utility membership class and authorized entering into membership agreements with non-utility members. On July 23, 2019, we filed with FERC our initial tariff, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. Our FERC tariff filing included our current Class A rate schedule (A-40) for electric power sales to our Members as the wholesale rates payable by our Members. Numerous parties filed interventions or protests with FERC.

On September 3, 2019, a membership agreement with a non-utility member, MIECO, Inc., became effective and we notified FERC of such and requested a partial waiver. The admission of the new member that was not an electric cooperative or governmental entity resulted in us no longer being exempt from FERC wholesale rate regulation pursuant to the FPA. On October 4, 2019, FERC issued an order rejecting our filings without prejudice to us submitting a more complete set of filings that cure the deficiencies set forth in such order. The FERC order did not rule on any of the substantive issues raised by those that filed interventions or protests.

During the week of December 23, 2019, we filed our revised set of filings, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. The request was made to FERC to make the new tariffs retroactive to September 3, 2019. Numerous parties filed interventions or protests with FERC. We expect FERC to rule on their acceptance of these tariffs by the end of March 2020. See "LEGAL PROCEEDINGS."

General

The electric power we provide to our Members continues to be at rates established by our Board, but such rates are now subject to FERC's approval. Our wholesale electric service contracts with our Members provide that rates paid by our 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 Members and non-member purchasers. Revenues from electric power sales to our Members are primarily from our Class A wholesale rate schedule. Our Class A rate schedule for electric power sales to our Members consist of three billing components: an energy rate and two demand rates. 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 Members. Energy is the physical electricity delivered to our Members. In 2019 (A-40 rate), 2018 (A-40 rate), and 2017 (A-40 rate), our Class A wholesale rate schedules used the same rate design. 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 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. This rate structure was filed at FERC as a "stated rate" where we requested FERC to approve the existing rate as stated. However, upon our next rate change, we will be required to justify the new rate at FERC with a rate case, likely to be contested. While our Board still has authority in determining our proper rates, those rates must be further approved by FERC subject to outside comments.

Approved by our Board in September 2019, the A-40 rate schedule will continue in effect for 2020 and that rate was filed at FERC on December 23, 2019 for acceptance by the end of March 2020.

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 Members to produce financial results above the requirements of our Master Indenture. Our management proposes rates that are expected to adequately recover our annual 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 Member rates. Any rate changes going forward will be filed at FERC for their acceptance.

The following table shows our average Member revenue/kWh for the years 2015 through 2019. The average Member revenue/kWh is our total Members' electric sales revenue in a given year divided by the total kilowatt hours sold to our Members in that given year. The average Member revenue/kWh does not represent the actual energy and demand rate components established by our Board and paid by our Members for the years 2015 through 2019.

Year	Average Member Revenue (Cents/kWh)
2019	7.599
2018	7.543
2017	7.544
2016	7.207
2015	7.133

Regulation of Rates

Our rates are established by our Board. However, we were required to file our Member rates with the NMPRC and, according to New Mexico law, the NMPRC had regulatory authority over our rates in New Mexico in the event three or more of our New Mexico Members filed a request to review our rates and the NMPRC found such request to be qualified. See "LEGAL PROCEEDINGS." However, now that our rates are FERC jurisdictional, we no longer have an obligation to file rates in New Mexico.

Under the FPA, an electric cooperative is not subject to rate regulation by FERC, if it is financed by the United States Department of Agriculture, Rural Utilities Service or it sells less than 4 million MWhs of electricity per year; or it is wholly owned, directly or indirectly, by any one or more of the foregoing. While each of our Members sells fewer than 4 million MWhs per year, the addition of non-cooperative members in 2019 and specifically the addition of MIECO, Inc. on September 3, 2019 removed the exemption from FERC regulation for us, thus subjecting us to full rate and transmission jurisdiction by FERC on September 3, 2019. Full rate regulation includes FERC reviewing our rates upon its own initiative or upon complaint and ordering a reduction of any rates determined to be unjust, unreasonable, or otherwise unlawful and ordering a refund for amounts collected during such proceedings in excess of the just, reasonable, and lawful rates.

In addition to its jurisdiction over rates, 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.

POWER SUPPLY RESOURCES

We provide electric power to our 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 2019, 61.5 percent of our energy available for sale was provided by our generation and 38.5 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 2019, we estimate that nearly a third of the energy delivered by us and our Members to our Member's customers came from non-carbon emitting resources. We estimate that 50 percent of the energy delivered by us and our Members to our Member's customers will come from renewable resources 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 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 1,782 MWs from coal-fired base load facilities and 903 MWs from gas/oil-fired facilities. See "PROPERTIES" for a description of our various generating facilities.

On September 19, 2019, our 100 MW Nucla Generating Station was officially retired from service. Nucla Generating Station, which had been in a ready-to-run status, was to be retired by the end of 2022 as required by Colorado's State Implementation Plan.

On December 31, 2019, our gas tolling arrangement with AltaGas Brush Energy Inc. to provide intermediate load generating capacity of 70 MWs from a combined-cycle facility located near Brush, Colorado expired.

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 are working with the other joint owners of Craig Station Unit 2 to determine the specific details for the retirement of Craig Station Unit 2. We own and operate the 448 MW Craig Station Unit 3. The early retirement of Craig Station is expected to impact approximately 253 employees.

On January 9, 2020, we also announced that our Board approved the early retirement of our 253 MW Escalante Station by the end of 2020. The early retirement of Escalante Station is expected to impact approximately 107 employees.

After the planned retirements of Craig Station and Escalante Station, our interest in coal-fired base load facilities is expected to decrease to 881 MWs, which is expected to be a decrease of over 50 percent compared to our 1,874 MWs of coal-fired base load interest in 2015.

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 Members' load in the Eastern Interconnection. The Members' peak load in the Eastern Interconnection in 2019 was approximately 305 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 five 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 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 1498 MWs, including 671 MWs of wind-based power purchase contracts and 800 MWs of solar-based power purchase contracts. The largest of these renewable power purchase contracts are summarized in the table below. A majority of these renewable power purchase contracts below 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**	**Facility Rating (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	91	2012		2032	
Coyote Gulch Solar	Colorado	Coyote Gulch Solar, LLC	Solar	120	2023	(1)	2038	(2)
Crossing Trails Wind	Colorado	Crossing Trails Wind Power Project, LLC	Wind	104	2020	(1)	2035	(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)	2035	(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 225 MWs, the largest of 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." We, through one of our wholly owned subsidiaries, had a contract that expired in June 2019 to sell PSCO 122 MWs in tolling capacity from the J.M. Shafer Generating Station.

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 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 CRSP, our decision to join SPP's Western Energy Imbalance Service market. Since then Municipal Energy Association of Nebraska and Wyoming Municipal Power Agency have also joined. SPP is expected to launch the Western Energy Imbalance Service market in February 2021. The market will centrally dispatch 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 plan to register as a CAISO scheduling coordinator, and register 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 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. 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.

Fuel 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	Trapper Mine and Colowyo Mine	2020 and 2027, respectively		800,000
Craig Station Unit 3	Colowyo Mine	2027		1,300,000
Escalante Station	El Segundo Mine	2020	(1)	250,000
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) Escalante Station is expected to be retired by the end of 2020.

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 developing 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, New Horizon Mine, Trapper Mine, Dry Fork Mine, and Fort Union 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. In 2019, we provided guarantees of, or performance bonds for, certain reclamation obligations of WFW and our subsidiaries. The amount of these performance bonds or guarantees are based upon applicable state requirements and are different than the amount of liabilities recognized on our financial statements in accordance with GAAP. We do not expect any changes in regulations that would reduce the amount we may guarantee of the reclamation obligations of WFW or our subsidiaries to have a material impact on us.

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 member, MIECO, Inc. Six major natural gas pipelines have interconnections at the Cheyenne Hub, and presently, there is 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.

We are involved in a proceeding in the State of New Mexico that could impact the water rights for Escalante Station. It is an adjudication of water rights associated with the Bluewater Toltec Area to determine the past, present and future use of water rights of the Pueblos of Acoma and Laguna, which we collectively refer to as the Pueblos. Specifically, the Pueblos are seeking a determination of the volume of ground water and surface water available to them and to determine the priority of those water rights. Should the Pueblos prevail in court, permitted water rights available for the Escalante Station will be significantly reduced, potentially requiring us to secure alternative water supplies at a cost which could potentially be higher than the cost of the water supplies currently being used.

We were also involved in a proceeding in the State of Colorado related to the water rights of Burlington Generating Station and that matter was dismissed without adverse impact to our water rights.

Resource Planning

We continually evaluate potential resources required to serve the long-term requirements of our 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 615 MWs of solar allowed us to add cost effective resources to our power supply portfolio. Based upon our current Member load/resource balance forecast, we do not anticipate a near term need for additional capacity.

The Colorado General Assembly in 2019 passed legislation that revises processes undertaken by the COPUC. Senate Bill 19-236, Sunset Public Utilities Commission, which was signed by the Colorado Governor on May 30, 2019, continues the COPUC for seven years. Among other provisions, the bill requires us to file and obtain COPUC approval for integrated or electric resource plans and directs the COPUC to require electric public utilities to consider the cost of CO_2 emissions in certain proceedings. On July 31, 2019, the COPUC opened a rulemaking pursuant to Senate Bill 19-236 proposing electric resource planning rules applicable to us. We, along with two Members and others, filed initial comments on September 11, 2019. We, along with others, also filed reply comments on September 25, 2019. The COPUC held an en banc hearing on the proposed rule on October 15, 2019 and subsequently held deliberations on the matter at its regular weekly public meeting on January 22, 2020. While a final commission decision is still pending, the COPUC did affirm a similar "Phase I/Phase II" electric resource planning process to us as it currently applies to Colorado's investor owned utilities. We are expecting to file an initial assessment of existing resources by June 1, 2020 with an application for approval of the full plan due by December 1, 2020. The bill and final rules could have a material impact on our operations and our future generation portfolio; however, until the final rules are enacted that implement the bill, it is not yet possible to estimate the impacts on our operations or future generation portfolio.

As part of our long-term resource planning, we have acquired real estate interests and water rights for a project called the Colorado Power Project located near Holly, Colorado. Through December 2019, we have incurred development costs of approximately $75.2 million, which is primarily the cost for the purchase of certain water rights and real estate interests, in connection with the Colorado Power Project. We have not yet selected a fuel or generation technology for this development, and we have not applied for an air permit for this development.

Over the past decade, in a joint effort with Sunflower, a Kansas generation and transmission cooperative, and others, we had pursued development of approximately 895 MWs of coal-fired base load generating capacity to be located near Holcomb, Kansas, at the site of the existing Holcomb Generating Station. During the second quarter of 2017, we determined the probability of us entering into construction for the project was remote. In January 2020, our Board officially canceled the Holcomb expansion project and committed to not develop additional coal-fired generating facilities.

TRANSMISSION

We have ownership or capacity interests in approximately 5,671 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 407 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 Generation & Transmission 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 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. Prior to September 3, 2019, we were not subject to the general "public utility" regulation of FERC under the FPA because of the exempt status of our Members. The addition of non-cooperative members in 2019 and specifically, the addition of MIECO, Inc. on September 3, 2019 removed this exemption. Thus, we are now subject to the general "public utility" regulation of FERC under the FPA and are now fully under FERC jurisdiction for rates and transmission service. We filed our electric tariff including the OATT in stages during the week of December 23, 2019 and we expect FERC to rule on the acceptance of those tariffs by the end of March 2020. See "LEGAL PROCEEDINGS." However, we have been operating under the FERC *pro forma* OATT since September 3, 2019. FERC requires both public utilities and non-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 "transmission-owning member" of SPP, a regional transmission organization, for our transmission facilities and loads that are located in the Eastern Interconnection and constitute about 3.6 percent of our total loads and 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. On December 30, 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. On February 23, 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. On May 17, 2018, FERC affirmed the initial decision and no refund was owed by us on this part of the matter. On June 15, 2018, NPPD filed with FERC a request seeking rehearing of FERC's May 17, 2018 order. On January 15, 2019, FERC denied NPPD's request for rehearing. On March 15, 2019, NPPD filed a petition for review at the United States Court of

Appeals for the Eighth Circuit. On January 15, 2020, oral arguments related to NPPD's petition took place before the Eighth Circuit.

On August 21, 2018, NPPD filed with FERC a complaint against us and SPP pursuant to Sections 206 and 306 of the FPA requesting FERC to find the inclusion of certain of our costs in our annual transmission revenue requirement causes SPP's OATT to be unjust and unreasonable. On September 17, 2018, SPP filed a motion to dismiss and alternative answer and we filed an answer requesting that FERC deny NPPD's complaint. On December 20, 2018, FERC issued an order denying the complaint. On January 18, 2019, NPPD filed with FERC a request seeking rehearing of FERC's December 20, 2018 order. On September 19, 2019, FERC denied NPPD's request for rehearing and dismissed the protest.

Open Access Transmission Service

Use of our transmission facilities is governed by OATTs. This arrangement flows from Order Nos. 888, 890, and 1000, which FERC issued in 1996, 2007 and 2011, respectively, as a means of promoting universal, non-discriminatory and "open" access to the nation's transmission grid. 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. In these orders, FERC generally required all transmission-owning public utilities to provide transmission service on an open access basis. Since 2001, we have offered transmission service under an OATT for service across our system on a non-discriminatory basis to satisfy the requirements of a non-public utility as defined by FERC. Beginning January 1, 2016, 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. Beginning September 3, 2019, we became fully FERC jurisdictional and began operating our Western Interconnection transmission facilities under the FERC *pro forma* OATT. During the week of December 23, 2019, we filed our entire electric tariff including the conforming OATT at FERC and we expect FERC to rule on the acceptance of this filing by the end of March 2020.

When we were a non-public utility, we were not required to implement the FERC Standards of Conduct which require separation between transmission operations and merchant operations (other than in connection with the reciprocity requirement described above). To ensure our compliance with the reciprocity requirement and contractual obligations relating to confidentiality and non-disclosure of protected transmission information, we implemented FERC's Standards of Conduct procedures in 2001, including procedures for transmission data confidentiality, by creating a physical and functional separation of protected transmission data from our employees and agents engaged in merchant functions. Now that we are fully FERC jurisdictional, we are required to implement the FERC Standards of Conduct. Since our program has fully complied with FERC since 2001, no changes were required.

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. Prior to the 1990's, most grid expansion planning was undertaken on a local basis, as utilities and, if applicable, state regulators determined which investments were appropriate to serve local customers. In Order No. 888, FERC encouraged utilities to coordinate their planning efforts with the expectation that integrated planning would better accommodate the development of regional, wholesale energy markets. In Order No. 890, FERC expressly required coordinated transmission planning, established governing principles, and cautioned that if non-public utilities did not participate in coordinated transmission planning, FERC may compel them to do so. 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. As it did with respect to open access transmission service, FERC stated that it may take action under Section 211A with respect to non-public utilities that do not comply with the requirements of Order No. 1000; however, FERC provides deference to non-public utilities to encourage their participation, in particular by not requiring non-public utilities to accept mandatory cost allocation. We voluntarily complied, while we were a non-public utility, with Order No. 1000 by participating in regional and interregional transmission planning and cost allocation processes in SPP and WestConnect. However, beginning September 3, 2019, we became fully FERC jurisdictional and are required as a public utility to participate in regional transmission planning. We notified the WestConnect participants of our change of status. In conjunction with other utilities in the surrounding geographic area, we participate in WestConnect, 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. In 2007, FERC also approved limited delegations of authority from NERC to eight regional entities. The delegations authorize each regional entity to propose regional reliability standards for their respective regions that would supplement or exceed the national standards. NERC has also delegated to the regional entities the authority to monitor and enforce compliance with the regional and national reliability standards, subject to NERC and FERC review.

For a majority of 2019, Peak Reliability performed the reliability coordination and interchange authority functions as required under the NERC standards in the Western Interconnection. As of December 3, 2019, Peak Reliability is no longer providing such service. On November 1, 2019, we began taking service from CAISO for our footprint in the PNM balancing authority and on December 3, 2019, we began taking service from SPP for our remaining footprint.

We are registered in two of the eight regional entities: WECC and MRO. WECC and MRO seek to sustain and improve the reliability of the electric grid through regional coordination, standard setting, certification of grid operators, reliability assessments, coordinated regional planning and operations, and dispute resolution. 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 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, also are authorized to conduct other types of investigations, including requiring annual "self-certifications" of compliance with select reliability standards. In 2015, NERC approved our participation in a new coordinated oversight program as a MRRE, whereby WECC was designated as our Lead Regional Entity. The intent of the MRRE program is to streamline compliance and enforcement efforts for entities registered in multiple regions.

In 2018, we were audited by WECC and are scheduled for a future compliance audit in 2021 as part of a three-year routine audit cycle. WECC has closed out all of the findings from the 2018 audit, and no penalties were assessed.

WECC stated that they have noticed the improvements we have made in our compliance implementation and have a good culture of compliance.

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 $14 million through 2024 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. 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 eighteen 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

The Colorado General Assembly in 2019 passed House Bill 19-1261, Climate Action Plan to Reduce Pollution, which was signed by the Colorado Governor on May 30, 2019. The legislation requires that the Air Quality Control Commission 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 Air Quality Control Commission has not yet developed or adopted rules to implement the legislation.

The New Mexico Legislature in 2019 passed Senate Bill 489, the Energy Transition Act, which was signed into law by the New Mexico Governor on March 22, 2019. The legislation amends the existing RPS that requires our New

Mexico Members to obtain 9 percent and 10 percent of their energy requirements from renewable sources in 2019 and 2020, respectively. The legislation adds requirements for our New Mexico 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 Members to obtain at least 6 percent in 2019 and 10 percent in 2020 and thereafter of their energy requirements from renewable sources and requires we provide to our Colorado 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 Members for their RPS requirement towards compliance with our separate RPS requirement.

We currently provide sufficient energy from renewable sources to meet our Members' current obligations under the RPS requirements in New Mexico and Colorado and expect to be able to continue meeting our Members' RPS obligations in 2020 to the extent a Member does not meet its obligation with renewable generation owned or controlled by such 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 Members at wholesale come from renewable sources in 2020.

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 announced as part of our Responsible Energy Plan, and other impacts additional to the closures of coal-fired generating facilities associated with the Responsible Energy Plan. See "– MEMBERS – Responsible Energy Plan" for information on our Responsible Energy Plan.

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 NOx 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, NOx, 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 NOx burners. Craig Station Unit 2 has selective catalytic reduction equipment for NOx control. Craig Station Unit 3 has selective non-catalytic reduction equipment for NOx control and an activated carbon injection system to control mercury emissions. Escalante Station has scrubbers to remove SO_2, baghouses for particulate removal, a laser-based system to optimize combustion for NOx emissions, and an activated carbon injection system to control mercury emissions. Springerville Unit 3 has scrubbers to remove SO_2, baghouses for particulate removal, low NOx burners and selective catalytic reduction equipment for NOx 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 NOx emissions by lowering thermal NOx formation.

Acid Rain Program. The acid rain program requires nationwide reductions of SO_2 and NOx 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 NOx 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. On October 16, 2017, the EPA published a proposal to repeal the Clean Power Plan. In July 2019, the EPA finalized the repeal of the Clean Power Plan.

On August 31, 2018, the EPA published in the Federal Register a proposed rule regarding emission guidelines for greenhouse gas emissions from existing generating units, commonly referred to as the Affordable Clean Energy rule. The Affordable Clean Energy rule is intended to replace the Clean Power Plan. In July 2019, the EPA finalized the Affordable Clean Energy rule which establishes 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. While the Affordable Clean Energy rule establishes that requirements be achievable based on adequately demonstrated technology, implementation of the rule will be at the state level, and it is too early to know how each state in which we operate will administer the rule. If a state implements a very strict interpretation of the rule, it may have a material impact on our operations. Legal actions were filed in opposition to and support of the Affordable Clean Energy rule. The D.C. Circuit Court of Appeals issued a briefing order indicating that briefing in the case will be complete by July 30, 2020. It is unlikely that legal arguments will take place before fall 2020, and a decision is unlikely for several months after that.

The EPA also issued a final NSPS for new units, which established CO_2 emission standards for new, modified and reconstructed units. On April 4, 2017, the EPA published in the Federal Register a notice that the EPA is reviewing and, if appropriate, will initiate proceedings to suspend, revise or rescind this NSPS. On August 8, 2017, the D.C. Circuit Court of Appeals issued an order to hold the legal proceeding in abeyance indefinitely and directed the EPA to file status reports at ninety-day intervals beginning October 27, 2017.

On December 20, 2018, the EPA published a proposed rule to revise the NSPS for new, modified, and reconstructed units. The EPA has yet to finalize this 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 believe we are in compliance with the rule's emission limits at our generating facilities and have the appropriate emission controls.

On December 26, 2018, the EPA signed a proposed rule to reconsider a supplemental finding related to the MACT rulemaking that has to do with consideration of costs. The proposal would not change the compliance obligations. In addition, the proposal would offer EPA's statutorily-required residual risk and technology review, the results of which are that current standards are protective and no new developments in hazardous air pollutant controls to achieve further cost-effective emission reductions were identified. The EPA has yet to finalize this rulemaking.

New Mexico, Colorado and Arizona adopted rules that require mercury monitoring and contain emission limits. Our coal-fired facilities are subject to these regulations. We have installed mercury monitors and comply with the state rules. In light of the federal rule, New Mexico repealed its state rule in 2014 and Colorado in 2015 amended its state rule to lessen the regulatory burden.

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 BART 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 NOx emissions from utility sources.

The states were required to develop their regional haze implementation plans by December 2007, identifying the facilities that would need to undergo BART determinations. The Reasonable Progress phase of meeting the Regional Haze Rule is the development of periodic visibility goals in order to meet a 2064 goal of natural visibility conditions. The Reasonable Progress phase SIPs establish standards and a timeline for meeting visibility goals. Colorado, New Mexico, Wyoming and Arizona previously developed their first SIPs, which are described below, and are now developing their second SIPs, which are due to the EPA by July 2021.

Under the existing, approved Colorado's SIP, we committed to NOx emissions rates that resulted in the installation of selective catalytic reduction on Craig Station Unit 2 and the owners of Craig Station Unit 1 will retire Craig Station Unit 1 by December 31, 2025 without any installation of selective catalytic reduction prior to its retirement.

Any source that emits SO_2, NOx, and particulates and that may contribute to the degradation of visibility in national parks and wilderness areas, identified as Class I areas, could be subject to additional controls. New Mexico opted to comply with SO_2 provisions of the Regional Haze Rule by putting in place a backstop SO_2 trading program. Arizona and New Mexico evaluated NOx emission impacts on visibility and moved forward to develop Reasonable Progress rules for NOx reductions. New Mexico's plan includes the closure of two units at San Juan Generating Station, including Unit 3, but neither state's current plan requirements affect our current assets. In Wyoming, after a settlement was reached in late 2016, selective non-catalytic reduction was installed on Laramie River Generating Station Units 2 and 3.

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.

State Implementation Plans. On June 12, 2015, the EPA published a final action in the Federal Register that takes action under the Clean Air Act, enacting SIP calls in states to change provisions to the current affirmative defense to civil penalties used by permitted sources, including electric utilities, in the event they have emissions during a startup, shutdown or malfunction event that are in excess of permitted limits. States retain broad discretion concerning how to revise their SIP, so long as that revision is consistent with the requirements of the Clean Air Act. The EPA issued the SIP call for 36 states, including Arizona, Colorado, New Mexico, and Wyoming. The EPA established a deadline of November 22, 2016, by which those states must have made SIP submissions to rectify the specifically identified deficiencies in their respective SIPs. Colorado completed a rulemaking process wherein the affirmative defense provisions were retained in federal court proceedings, should a federal court wish to consider the affirmative defense provisions. New Mexico and Arizona completed rulemakings wherein the affirmative defense provisions were removed from SIPs and maintained as state regulatory provisions. At this time, we cannot predict the outcome of the EPA's consideration of these submittals.

Water Quality

The Clean Water Act. The Clean Water Act regulates the discharge of process wastewater and certain storm water under the NPDES 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.

As permitted by the State of Colorado under the Colorado Discharge Permit System (a delegated NPDES program), Rifle Generating Station discharges process wastewater to nearby water bodies. Rifle Generating Station discharges to a dry ditch (unnamed tributary to Dry Creek) that flows to the Colorado River. J.M. Shafer Generating Station discharges indirectly under an EPA pretreatment permit to the City of Fort Lupton wastewater treatment facility through a pond system. Our other facilities have on-site containment ponds where water is evaporated and have no surface water discharges. We also have NPDES storm water permits for Craig Station and Escalante Station. We maintain Stormwater Pollution Prevention Plans as required in the stormwater permits to ensure that stormwater run-off is not impacted by industrial operations. We currently have construction stormwater permits for numerous transmission line and generation construction projects. These construction permits will be terminated once adequate vegetation is established at the sites, which can take several growing seasons. Escalante Station and Pyramid Generating Station have groundwater discharge permits administered by the New Mexico Environment Department, which governs the pond systems at both facilities and on-site ash landfill at Escalante Station. The pond systems are designed to reuse or store and evaporate water.

Section 316(b) of the Clean Water Act requires the EPA to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. Section 316(b) is applicable to Craig Station; however, impacts are minor as the facility operates a closed cycle cooling system minimizing impingement and entrainment.

On March 6, 2017, the EPA and the U.S. Army Corps of Engineers 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, which the EPA and the U.S. Army Corps of Engineers announced on January 23, 2020.

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. At Escalante Station, the combustion by-products are placed in designated landfills. The mine-fill and landfills are regulated by state environmental agencies and all required permits are in place. In 2010, the EPA proposed two options for regulating combustion by-products under RCRA. One option is regulation as a solid waste under RCRA Subtitle D; the second option is regulation as a hazardous waste under Subtitle C. The EPA in December 2014 announced that it chose to pursue regulations as a solid waste under Subtitle D of RCRA. The final Coal Combustion Residual rule was published in the Federal Register on April 17, 2015. The rule contains varying deadlines for the various compliance obligations, some of which needed to be met by the initial compliance deadline of October 19, 2015. The final federal rule is self-implementing and thus affected facilities must comply with the new regulations even if states do not adopt the rule. We estimate our total costs relating to the management of such by-products to be approximately $10 million over the life of our facilities. We are meeting all initial compliance obligations that became effective on October 19, 2015. In December 2016, Congress passed the WIIN Act. The WIIN Act provides for the establishment of state and EPA permit programs for coal ash. The Act provides flexibility for states to incorporate the EPA final rule for coal combustion residuals or develop other criteria that are at least as protective as the final rule. The WIIN Act was signed into law by President Obama on December 16, 2016. At this time, we are monitoring state actions and cannot predict state actions or impacts. In August and December 2019, the EPA proposed amendments to the rule to address several technical and compliance-related issues pursuant to a settlement from litigation about the Coal Combustion Residuals 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 July 1, 2017, President Trump announced that the United States would begin a process to withdraw from the Paris 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 July 25, 2018, the Center for Biological Diversity and Sierra Club filed a complaint against the CDPHE in opposition to CDPHE's issuance of an air permit for construction and operation of the Collom pit at the Colowyo Mine. We and Colowyo Coal on August 23, 2018 filed an unopposed motion to intervene and answer to the complaint. The CDPHE on September 4, 2018 filed an answer and defenses to the complaint. On February 14, 2019, the court issued a stay of the case proceedings until May 1, 2019, while CDPHE processes a permit revision. As the permit revision was still pending on April 30, 2019, we filed a Motion for Stay Extension. On May 21, 2019, the Center for Biological Diversity and Sierra Club filed an Opposition to Motion for Stay Extension. On May 28, 2019, the court granted our motion to extend the stay until October 29, 2019. On August 13, 2019, CDPHE issued the public notice for commenting on the revision to the air permit. The 60-day public comment period began on August 14, 2019 and ended on October 12, 2019. We filed selective comments on October 11, 2019. On November 7, 2019, the Collom air permit revision 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 December 20, 2019, all parties agreed to file a Joint Motion to Dismiss the litigation on the original air permit. On January 16, 2020, the judge granted the Joint Motion to Dismiss the original Collom air permit case. In regard to the new case, we filed a motion to intervene as an intervenor-defendant on January 28, 2020.

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. Past litigation from environmental groups resulted in the U.S. Fish and Wildlife Service being placed on a schedule to make determinations as to whether or not numerous species should be formally listed as threatened or endangered under the Endangered Species Act. Once listed, a species of animal or plant with threatened or endangered status may complicate, delay, and/or add costs to projects. Of the several hundred species involved in the litigation settlement, we estimate that approximately 30 had the potential to affect our operations. Species of particular concern due to their geographic range and potential impacts to mining and transmission assets are the greater sage-grouse, the Gunnison sage-grouse, and the lesser prairie-chicken. In September 2015, the U.S. Fish and Wildlife Service determined that it was not warranted to list the greater sage-grouse under the Endangered Species Act, in large part due to federal land management agency conservation plans. The Bureau of Land Management and U.S. Forest Service conservation plans from 2015 were reviewed and revised further during 2017 and 2018. We commented in 2017 and 2018 during the Bureau of Land Management's review process. The Gunnison sage-grouse was addressed in amendments to a local Bureau of Land Management Resource Management Plan and the U.S. Fish and Wildlife Service may issue a Special 4(d) rule for the species in the future. After its listing as a threatened species was vacated, the lesser prairie-chicken underwent another review under the Endangered Species Act. A decision whether or not to list the lesser prairie-chicken was expected in 2018 but was not released. We are monitoring each of these issues as they develop over time. In addition to species-specific actions, the U.S. Fish and Wildlife Service in 2018 proposed three rules aimed at improving various regulatory and compliance processes under the Endangered Species Act. In August 2019, the U.S. Fish and Wildlife Service finalized the three reform rules.

ITEM 1A. RISK FACTORS

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

Successful state or federal jurisdictional claims in 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, including all obligations under its wholesale electric service contract with us. By the addition of a non-cooperative member in 2019 and specifically by the addition of MIECO, Inc. as a member on September 3, 2019, we became a FERC jurisdictional "public utility" under Part II of the FPA. In November 2019, United Power and LPEA filed complaints with the COPUC alleging that the COPUC has jurisdiction over the equitable terms and conditions as our Board may prescribe for withdrawal and seeking the COPUC to establish a withdrawal number or exit charge. In December 2019, we filed our Petition for Declaratory Order with FERC asking FERC to confirm our jurisdictional under the FPA and that FERC's jurisdiction preempts the jurisdiction of the COPUC to address any rate related issues, including the complaints filed by United and LPEA. Some of the interveners and protestors in our Petition for Declaratory Order, including some of our Members and the COPUC, are alleging that we are not FERC jurisdictional and are still exempt from FERC wholesale rate regulation pursuant to the FPA. See "LEGAL PROCEEDINGS."

If the COPUC or any other state commission or state regulatory body is successful in asserting that it has jurisdiction over the terms and conditions for a Member's withdrawal from us, including the complaints filed by United and LPEA, and if the COPUC or any other state jurisdiction or state regulatory body determines the terms and conditions for a Member to withdraw that are less than the monetary value as our Board may proscribe, it may materially impact us. If we are successful in asserting that FERC has sole jurisdiction over the terms and conditions for a Member's withdrawal from us and FERC determines the terms and conditions for a 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 Member's obligation or a significant number of our Members withdraw, it may materially impact us.

The material impacts could include increased rates to our 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.

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

Wholesale rate increases for our Members must be approved by a majority of our Board, which is comprised of one representative from each of our 43 Members and is now also subject to FERC's approval. By the addition of a non-cooperative member in 2019, and specifically by the addition of MIECO, Inc. as a member on September 3, 2019, we became FERC jurisdictional for our Member rates, transmission service, and our market based rates. We filed our tariffs for wholesale electric service and transmission at FERC in stages between December 23 and 27, 2019, with supplemental filings completed by December 30, 2019. Our existing Class A wholesale rate structure (A-40) to our Members was filed at FERC as a "stated rate" where we requested FERC to approve the existing rate as stated. We expect FERC to rule on their acceptance of these tariffs, including our existing wholesale rate structure to our Members, by the end of March 2020. See ''LEGAL PROCEEDINGS." Upon our next rate change, we will be required to justify the new rates to our 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 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 to defer expenses associated with the early retirements of our generating facilities to implement the Responsible Energy Plan or the utilization of regulatory liabilities to ensure our Member rates remain stable, during this transition to a cleaner generation portfolio 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 Members and, as a result, could affect their ability to perform their contractual obligations to us. In addition, we may experience additional Member unrest and desires to withdrawal from our 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.

We were operating as a FERC-jurisdictional public utility making sales and providing services without satisfying the FPA's filing obligations and FERC's prior notice requirement. We may be subject to certain penalties, fines and/or refunds.

On July 23, 2019, we filed with FERC our initial tariff, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. Our FERC tariff filing included our current Class A rate schedule for electric power sales to our Members as the wholesale rates payable by our Members. On September 3, 2019, a membership agreement with a non-utility member, MIECO, Inc., became effective and we notified FERC of such and requested a partial waiver. The admission of the new member that was not an electric cooperative or governmental entity resulted in us no longer being exempt from FERC wholesale rate regulation pursuant to the FPA. On October 4, 2019, FERC issued an order rejecting our filings without prejudice to us submitting a more complete set of filings that cure the deficiencies set forth in such order. During the week of December 23, 2019, we filed our revised set of filings, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. The request was made to FERC to make the new tariffs retroactive to September 3, 2019. Until we made our reapplication in December 2019, we were a FERC-jurisdictional public utility making sales and providing services without satisfying the FPA's filing obligations and FERC's prior notice requirements. FERC may require us to refund to our customers certain amounts collected for the entire period that the rate was collected without FERC's authorization, including Member and non-member electric sales and wheeling revenue. FERC may also impose civil penalties for the time period between when we became a FERC-jurisdictional public utility and when we made our reapplication in December 2019. Furthermore, current practices including our use of regulatory assets are subject to FERC approval and subject to change as a result. It is not possible to predict if FERC will require us to refund amounts, the scope of such refunds to our customers, if FERC will impose civil penalties, if FERC will approve our current practices regarding use of regulatory assets, or to estimate any liability associated with this matter. In addition, our customers may dispute their obligation to pay us or pay under protest because we do not have FERC approved rates.

Although we expect that our revised filings with FERC will cure the deficiencies set forth in FERC's rejection of our initial filing, there is no guarantee that FERC will accept our revised filing, that FERC will accept our revised filing subject to refund or that FERC will conclude that we are a FERC- jurisdictional "public utility."

By the addition of a non-cooperative member in 2019 and specifically by the addition of MIECO, Inc. as a member on September 3, 2019, we became a FERC-jurisdictional "public utility" under Part II of the FPA. On October 4, 2019, FERC issued an order rejecting our initial July 23, 2019 filings without prejudice to us submitting a more complete set of filings that cure the deficiencies set forth in such order. During the week of December 23, 2019, we filed our revised set of filings, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. Some of the interveners and protestors in our revised tariff filing, including some of our Members and the COPUC, are alleging that we are not FERC jurisdictional and are still exempt from FERC wholesale rate regulation pursuant to the FPA. There can be no guarantee that FERC will accept our revised filings or that FERC will conclude or rule on our status as a FERC-jurisdictional "public utility." If FERC rejects our revised filing or does not conclude or rule on our status of a FERC-jurisdictional "public utility," our future business plans may be impacted. If FERC does not conclude or rule on our status of a FERC-jurisdictional “public utility,” we may be subject to further and increased pressure by the states, including the COPUC, to regulate our rates and charges to our Members, including the withdrawal number or exit charges associated with Member withdrawals and any buy-down numbers associated with partial requirements contracts. If FERC accepts our filing subject to refund, we may be required to accrue certain liabilities associated with the amounts subject to refund and may be required to refund certain revenue collected.

Our Responsible Energy Plan may not achieve 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, and provide community support for transitioning communities. Although we believe that our Responsible Energy Plan addresses Member concerns regarding access to more renewable energy, addresses environmentalist concerns regarding clean energy, addresses lender concerns regarding increasing our renewable energy portfolio, 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. If our Members, environmentalists, lenders, local communities, or other stakeholders do not accept our Responsible Energy Plan or believe that we have adequately addressed their concerns through the adoption of our Responsible Energy Plan, we may experience additional Member unrest and desires to withdrawal, unfavorable media coverage or other negative consequences which may impact our financial condition or future plans.

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. In 2019, our existing generating facilities generated approximately 61.5 percent of our energy available for sale, a substantial percentage of which is generated by coal-fired generating facilities.

Existing and any additional federal or local environmental restrictions imposed on our operations, including RPS requirements imposed on us or our 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 announced as part of our Responsible Energy Plan, and may substantially increase the cost of electricity to our Members. 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. Examples of existing legislation and the implementation regulations to address limitations on CO_2 emissions and RPS are discussed below.

The Colorado General Assembly in 2019 passed House Bill 19-1261, Climate Action Plan to Reduce Pollution, which was signed by the Colorado Governor on May 30, 2019. The legislation requires that the Air Quality Control Commission 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 Air Quality Control Commission has not yet developed or adopted rules to implement the legislation.

The New Mexico Legislature in 2019 passed Senate Bill 489, the Energy Transition Act, which was signed into law by the New Mexico Governor on March 22, 2019. The legislation amends the existing RPS that requires our New Mexico Members to obtain a percentage of their energy requirements from renewable sources. The legislation adds requirements for our New Mexico 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.

In July 2019, the EPA finalized the Affordable Clean Energy rule. The Affordable Clean Energy rule establishes 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. While the Affordable Clean Energy rule establishes that requirements be achievable based on adequately demonstrated technology, implementation of the rule will be at the state level, and it is too early to know how each state in which we operate will administer the rule. If a state implements a very strict interpretation of the rule, it may have a material impact on us.

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. Failure to comply with existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could cause the complete temporary or permanent shutdown of individual generating units not in compliance with these regulations.

We operate in a capital-intensive industry and therefore debt comprises a majority of our capital structure.

As of December 31, 2019, we had total debt and short-term borrowings outstanding of approximately $3.4 billion, of which approximately $2.8 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 Members and to meet our other long-term electricity supply obligations. If demand for electricity from our 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 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.

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 2020 through 2024, after taking into account our Responsible Energy Plan, we estimate that we may invest approximately $877 million in new facilities and upgrades to our existing facilities which may require us to take on additional long-term debt.

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

- market conditions generally;
- an 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;
- 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, 2019, we had $527.7 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.

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. 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 announced as part of our Responsible Energy Plan, and thereby significantly increasing the cost of electric service we provide to our Members and affecting their ability to perform their contractual obligations to us.

Our financial condition is largely dependent upon our Members.

Our financial condition is largely dependent upon our Members satisfying their obligations under their wholesale electric service contracts with us. In 2019, 92.8 percent of our revenues from electric sales were from our 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 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 Members or because of intentional actions by our Members. Our results of operations and financial condition could be adversely affected if a significant portion of our Members default on their obligations to us.

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. The Energy Policy Act of 1992 amended the FPA to allow for increased competition among wholesale electricity suppliers and increased access to transmission services by such suppliers. Competing energy suppliers are targeting our Members by claiming to be able to offer lower priced and cleaner wholesale electric power. This includes assisting our Members in seeking to withdrawal from membership in us and financing the withdrawal number payable by our Members. On the retail side, states in which our 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 Members and the pool from which we recover fixed costs, resulting in higher rates to our Members. Competing energy suppliers are also targeting the communities our Members serve by claiming to be able to offer lower priced and cleaner wholesale electric power. It also includes assisting the communities our Members serve by helping them create electric utilities. In addition, federal legislation could mandate retail choice in every state.

We and our 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 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 Members could reduce our electricity demand from our Members and the pool from which we recover fixed costs, resulting in higher rates to our Members and reduced access to the capital markets.

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 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 Members withdrawal from membership in us, annexations by municipalities, helping municipalities our 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 Members may withdrawal, rates to our Members may increase or our financial condition and results of operations could be adversely affected.

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

Our mission is to provide our Members with a reliable, affordable and responsible supply of electricity in accordance with cooperative principles. Significant changes are taking place 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, 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 announced as part of our Responsible Energy

Plan, resulting in higher rates to our Members. Increased self-generation and the related use of net energy metering, which allows our Members' self-generating customers to receive bill credits for surplus power, could reduce demand for electricity from our 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.

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

Based on the most recent information available to us, which is 2018 data, industrial and large commercial customers account for approximately 41 percent of our Members' energy sales. A large percentage of these sales are in energy production, extraction and transportation. The 15 largest customers of our Members, a substantial percentage of which are in energy production, extraction and transportation, total approximately 17.4 percent of the aggregate retail electric energy sales of our Members, based on the same 2018 data. Outages at facilities of these large customers could reduce demand from and energy sales to our Members. A significant 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 accordingly or elect to self-generate.

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

Our decisions to meet our 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 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 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 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 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 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 2020 through 2024, we estimate that we may invest approximately $482 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;
- 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 Generation 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. The decommissioning costs may exceed our estimate, which could negatively impact 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 ensure our Member rates remain stable, 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 Members and, as a result, could affect their ability to perform their contractual obligations to us. In addition, we may experience additional Member unrest and desires to withdrawal from our Members.

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 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;
- availability and cost of fuel;
- fuel supply interruptions, including transportation interruptions;
- availability and cost of water;
- water supply interruptions;
- 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. 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.

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 co owned plants, could be directly or indirectly affected by deliberate or unintentional cyber incidents. Our industry has begun 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 Members. A major cyber incident could result in significant business disruption, compromised or improper disclosure of data, and expenses to repair security breaches or system damage and could lead to litigation, regulatory action, including penalties or fines, and an adverse effect on our financial condition, results of operations, and reputation. Moreover, the amount and scope of insurance maintained against losses resulting from any such cyber incident may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. In addition, as cybercriminals become more sophisticated, the cost of proactive defensive measures may increase. We also may have future compliance obligations related to new mandatory and enforceable NERC reliability standards addressing the impacts of geomagnetic disturbances and other physical security risks to the reliable operation of the bulk power system.

We may 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 in which we have ownership interests. Any disruptions in our fuel supplies, including disruptions due to weather, labor relations, 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 bottlenecks 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.

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 Members has increased. The plaintiffs in these actions have claimed that we are jointly liable for the actions of our 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 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 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 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.

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

We have ownership or capacity interests in approximately 5,671 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 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 2019, purchased power provided 38.5 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 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 14.2 percent and 13.4 percent, respectively, of our Member sales in 2019. 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. If we would have to pay significantly higher prices under these contracts, it could have an adverse effect on our results of operations.

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

Many of our employees are covered by collective bargaining agreements, and other employees may seek to be covered by collective bargaining agreements. 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 existing, 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
Escalante Generating Station	New Mexico	100.0	Coal	253	253	1984
Laramie River Generating Station Unit 1	Wyoming	27.1	Coal	570	0	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	417	417	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 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. On January 9, 2020, we announced that our Board approved the early retirement of Craig Station Units 2 and 3 by 2030.

Escalante Generating Station. Escalante Station is a 253 MW coal-fired electric generating facility located near Prewitt, New Mexico. Escalante Station is wholly owned and operated by us. On January 9, 2020, we announced that our Board approved the early retirement of Escalante Station by the end of 2020.

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 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 417 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 417 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. 122 MWs was sold to PSCO under a tolling agreement that expired in June 2019. After expiration of such PSCO tolling agreement, 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.

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, 2019, 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	3,243
138	173
230	1,117
345	1,082
Total	5,671

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 407 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 either our subsidiaries or our membership in third parties, have an ownership interest in the coal mines identified in the table below.

Mine	Location
Colowyo Mine(1)	Colorado
New Horizon Mine(2)	Colorado
Trapper Mine(3)	Colorado
Dry Fork Mine(4)	Wyoming
Fort Union Mine(5)	Wyoming

(1) Colowyo Mine is owned by Colowyo Coal, our indirect wholly owned subsidiary. On January 9, 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.
(2) New Horizon Mine is owned by Elk Ridge, our wholly owned subsidiary. New Horizon Mine is in mine reclamation and no longer produces coal.
(3) Trapper Mine is owned by Trapper Mining. We, along with certain participants, in the Yampa Project, own Trapper Mining. We have a 26.57 percent cooperative member interest in Trapper Mining.
(4) Dry Fork Mine is owned by WFW. 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.
(5) The land and rights to mine the Fort Union Mine are owned by us and Basin.

ITEM 3. LEGAL PROCEEDINGS

LPEA and United. 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, 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 have hindered LPEA's ability to seek withdrawal from us. LPEA alleges, among other things, that our Board's temporary suspension of providing Members with withdrawal numbers is unlawful. LPEA seeks the COPUC to issue an order related to our temporary suspension and for the COPUC to establish the withdrawal number. On November 6, 2019, United filed a formal complaint with the COPUC, alleging that we have hindered United's ability to explore its power supply options by either withdrawing from us or continuing as a member under a partial requirements contract. United alleges, among other things, that we have failed to provide a just, reasonable, and non-discriminatory withdrawal number. United seeks for the COPUC to issue an order establishing a withdrawal number. LPEA and United constitute approximately 5.6 percent and 16.6 percent, respectively, of our Member revenue in 2019. On November 20, 2019, the COPUC consolidated the two proceeding into one, 19F-0621E, and provided that the consolidated proceeding shall be heard before one hearing commissioner. On December 23, 2019, we filed a motion to stay the schedule in the proceeding pending the FERC's decision on our Petition for Declaratory Order filed with FERC regarding the COPUC's jurisdiction over us, including our Members' early termination of obligations under wholesale electric service contracts with us and withdrawal from membership in us. LPEA and United filed their direct testimony on January 10, 2020 and we filed our answer testimony on February 12, 2020. A number of interventions have been filed by our Members, including Members from each of our four states. By interim decision of the hearing commissioner on January 30, 2020, all motions to intervene were denied. A number of Members filed motions contesting the interim decision denying the interventions, which motions were denied by the hearing commissioner. On February 12, 2020, by interim decision of the hearing commissioner, the hearing commissioner denied our December 23, 2019 motion to stay the proceeding and determined that the COPUC has jurisdiction over the complaints of United and LPEA and the complaints are ripe for review by the COPUC. On February 26, 2020, we filed our answers to the formal complaints filed by LPEA and United. A five-day evidentiary hearing is scheduled to begin on March 23, 2020.

FERC Tariff and Declaratory Order. Because of increased pressure by the states to regulate our rates and charges, through the addition of a non-cooperative member in 2019 and specifically by the addition of MIECO, Inc. as a member on September 3, 2019, we became FERC jurisdictional for our Member rates, transmission service, and our market based rates. We filed our tariff for wholesale electric service and transmission at FERC on December 23, 2019. We filed our tariffs for wholesale electric service and transmission at FERC in stages between December 23 and 27, 2019, with supplemental filings completed by December 30, 2019. The request was made to FERC to make the new tariffs retroactive to September 3, 2019. Nine parties have filed protests, including five Members. Nine interventions have been filed including four Members intervening in support. In addition, on December 23, 2019, we filed our Petition for Declaratory Order with FERC asking FERC to confirm our jurisdiction under the FPA and that FERC's jurisdiction preempts the jurisdiction of the COPUC to address any rate related issues, including the complaints filed by United and LPEA, EL20-16-000. Thirteen parties filed interventions and/or protests, including seven by Members, four in support, two in protest, and one taking no position. A number of comments in support have been filed with FERC, including supporting comments from three Members. Some of the interveners and protestors in both our tariff filing and our Petition for Declaratory Order, including some of our Members and the COPUC, are alleging that we are not a FERC-jurisdictional public utility and are still exempt from FERC wholesale rate regulation pursuant to the FPA. Until we made our reapplication in December 2019, we were a FERC-jurisdictional public utility making sales and providing services without satisfying the FPA's filing obligations and FERC's prior notice requirements. FERC may require us to refund to our customers certain amounts collected for the entire period that the rate was collected without FERC's authorization, including Member and non-member electric sales and wheeling revenue. FERC may also impose civil penalties for the time period between when we became a FERC-jurisdictional public utility and when we made our reapplication in December 2019. Furthermore, current practices including our use of regulatory assets are subject to FERC approval and subject to change as a result. It is not possible to predict if FERC will require us to refund amounts to our customers, if FERC will impose civil penalties, if FERC will approve our current practices regarding use of regulatory assets, or to estimate any liability associated with this matter. We cannot predict the outcome of our tariff filings or our Petition for Declaratory Order, but expect FERC to rule on our tariff filings by the end of March 2020.

FERC Fixed Cost Recovery Petition. On February 17, 2016, we filed a Petition for Declaratory Order with FERC seeking a declaratory order from FERC finding that the fixed cost recovery mechanism in our revised Board policy is consistent with the provisions of PURPA and the implementing regulations of FERC. The revised Board policy provides for recovery of the unrecovered fixed costs directly from a Member as a result of that Member purchasing power from a "qualifying facility" in an amount that causes it to exceed the 5 percent limitation on that Member's self-supply of power pursuant to its wholesale electric service contract, rather than allocating the costs among all of our Members. The fixed cost recovery is calculated based on the difference between our wholesale rate to our Members and our avoided costs. Various individuals and entities filed comments and four entities filed motions to intervene, including our Member, DMEA. On June 16, 2016, FERC denied our Petition for Declaratory Order related to the fixed cost recovery mechanism in our revised Board policy. On July 18, 2016, we filed a Request for Rehearing with FERC regarding FERC's June 16 order. In addition, five other generation and transmission cooperatives filed a Request for Rehearing with FERC. We cannot predict the outcome of our July 18 request for rehearing filed with FERC.

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 Members. In November 2012, three of our 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 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 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. No initial scheduling conference in the federal proceeding has been scheduled and the parties periodically file status reports with the Court. On December 9, 2015, we and the New Mexico 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 seek 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 Members as a result of the suspension of prior rate filings. We cannot predict the outcome of this matter or if a global settlement will be reached, although we do not believe this proceeding is likely to have a material adverse effect on our financial condition or our future results of operations or cash flows.

Water Proceedings. We are involved in a water rights proceeding in the State of New Mexico that could impact the water rights for Escalante Station. It is an adjudication of water rights associated with the Bluewater Toltec Area to determine the past, present and future use of water rights of the Pueblos of Acoma and Laguna. We cannot predict the outcome of this matter, although we do not believe this proceeding is likely to have a material adverse effect on our financial condition or our future results of operations. See "BUSINESS — POWER SUPPLY RESOURCES — Water Supply."

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

The following tables set forth our selected consolidated financial data as of the dates for the years indicated. This consolidated financial data is qualified in its entirety by and should be read in conjunction with the more detailed information and the audited financial statements, including the notes to such financial statements, and the "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7.

	For the years ended December 31,				
	2019	2018	2017	2016	2015
Income Statement Data					
Operating revenues	$ 1,385,472	$ 1,320,837	$ 1,388,593	$ 1,341,096	$ 1,335,448
Operating expenses	(1,219,047)	(1,159,444)	(1,204,896)	(1,194,090)	(1,157,479)
Operating margins	166,425	161,393	183,697	147,006	177,969
Interest expense	(151,470)	(153,704)	(147,608)	(144,877)	(142,570)
Net margins attributable to the Association	45,309	42,734	61,656	31,748	53,413

	As of December 31,				
	2019	2018	2017	2016	2015
Balance Sheet Data:					
Total assets	$ 5,085,818	$ 5,026,867	$ 4,893,594	$ 4,911,291	$ 4,823,047
Electric plant, in service, less accumulated depreciation	3,448,922	3,399,752	3,393,824	3,321,058	3,245,786
Construction work in progress	164,924	207,732	175,567	212,081	216,279
Long-term debt	3,063,351	3,109,301	3,120,286	3,139,705	3,273,538
Patronage capital equity	1,031,063	1,015,754	1,003,020	961,364	952,082
Accumulated other comprehensive income (loss)	(1,518)	375	(210)	(286)	589
Noncontrolling interest	111,717	110,169	111,295	109,147	108,757
Total capitalization	$ 4,204,613	$ 4,235,599	$ 4,234,391	$ 4,209,930	$ 4,334,966

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 are organized for the purpose of providing electricity to our forty-three Members that 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 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. As of December 31, 2019, our Members served approximately 624,000 retail electric meters over a 200,000 square-mile area.

We are owned entirely by our forty-six members. Thirty-nine 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. 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.

In 2019, we sold 18.1 million MWhs, of which 90.6 percent was to Members. Total revenue from electric sales was $1.3 billion for the year ended December 31, 2019, of which 92.8 percent was from Member sales. Our results for the year ended December 31, 2019 were primarily impacted by:

- Non-member electric sales increased by $60.6 million, or 174.4 percent, primarily due to the recognition of $6.2 million of previously deferred non-member revenue as part of our Member rate stabilization measures and more favorable pricing for term sales during the year.
- Fuel expense increased $42.6 million, or 17.9 percent, primarily due to greater generation from our generating facilities, increased environmental reclamation obligations at New Horizon Mine, and increased asset retirement obligations during the period.
- General and administrative expense increased $16.6 million, or 50.1 percent, primarily due to an increase in outside professional services as well as an increase related to general and administrative labor and benefits.

Our Bylaws and Wholesale Electric Service Contracts

Pursuant to our Bylaws, each Member is required to purchase from us the electric power and energy provided in the wholesale electric service contract with such Member. Our wholesale electric service contracts with our Members extending through 2050 for 42 Members (which constitute approximately 96.8 percent of our revenue from Member sales for the year ended December 31, 2019) and extending through 2040 for the remaining Member (Delta-Montrose Electric Association, or DMEA) are substantially similar. These contracts are subject to automatic extension thereafter until either party provides at least a two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Member and obligates the Member to purchase and receive, at least 95 percent of its electric power requirements from us. Each Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Member. As of December 31, 2019, 21 Members have enrolled in this program with capacity totaling approximately 136 MWs of which 123 MWs are in operation. See also "BUSINESS – MEMBERS – Contract Committee" for a description of our community solar program for our Members.

Pursuant to our wholesale electric service contracts with our Members, we convened a contract committee in 2019, consisting of a representative from each Member, to review the wholesale electric service contracts and to discuss alternative contracts for our Members, including partial requirements contracts. In February 2020, the contract committee recommended to the Board and the Board announced a commitment to provide our Members with the option of entering into a partial requirements contract. The partial requirements option is subject to further refinement, but is expected to include holding an open season for Members to choose to enter into a partial requirements contract and the open season would permit Members collectively to self-supply up to 300 MWs, approximately 10 percent of our peak system demand. In addition, additional open seasons could be offered in the future and Members that choose the partial requirements option will make other Members financially whole through a buy-down payment or payments. The Board further directed the contract committee to make recommendations to the Board on the specific details for the partial requirements contracts, including the partial requirements buy-down methodology and the process for implementing the offering.

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, including all obligations under its wholesale electric service contract with us. From time to time, a 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 Members equitable terms and conditions for withdrawal. In addition, from time to time, we may be in discussions with a Member regarding the equitable terms and conditions for withdrawal and their request for withdrawal, including granting a 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 Member's requirements and obligation to comply with such equitable terms and conditions as our Board may prescribe. As part of the contract committee considering partial requirements contracts, and the interaction with shopping letters and the withdrawal number for a Member to meet all its contractual obligations to us, at our September 2019 Board meeting, our Board approved a temporary suspension of the policy and practice of providing its Members with withdrawal numbers and shopping letters. The suspension is expected to continue until the contract committee has completed its work and provided recommendations to our Board, our Board has had an opportunity to consider and act upon such recommendations, and our Board has fully assessed the financial impacts of Member withdrawals and/or the offering of alternative contracts. At our September 2019 Board meeting, our Board also authorized the contract committee to consider alternative methods to determine the withdrawal number with a goal of completing such work and presenting it to our Board by April 2020.

In July 2019, we reached a settlement with DMEA that provides 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 amount of the withdrawal payment was the product of the negotiated settlement with DMEA and is unique to DMEA because of the amounts associated with the transmission assets being transferred and patronage capital, and the date of withdrawal of DMEA from us. The specific terms of the settlement will be set forth in a withdrawal agreement, which will be subject to receipt of certain approvals and other conditions. The settlement agreement provides for the parties to cooperate to complete DMEA's withdrawal effective May 1, 2020, but we expect the withdrawal effective date to occur at a later date agreed to by the parties.

In November 2019, LPEA filed a formal complaint with the COPUC alleging that we have hindered LPEA's ability to seek withdrawal from us. LPEA alleges, among other things, that our Board's temporary suspension of providing Members with withdrawal numbers is unlawful. LPEA seeks for the COPUC to issue an order related to our temporary suspension and for the COPUC to establish the withdrawal number. In November 2019, United filed a formal complaint with the COPUC alleging that we have hindered United's ability to explore its power supply options by either withdrawing from us or continuing as a member under a partial requirements contract. United alleges, among other things, that we have failed to provide a just, reasonable, and non-discriminatory withdrawal number. United seeks for the COPUC to issue an order establishing a withdrawal number. The COPUC has consolidated the proceeding. A five-day evidentiary hearing is scheduled to begin on March 23, 2020. See "LEGAL PROCEEDINGS."

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 Member flexibility, all with a goal to lower wholesale rates to our Members. In January 2020, we announced the actions of our Responsible Energy Plan, which will advance our cleaner generation portfolio and programs to serve our Members. Some of the actions of the Responsible Energy Plan include:

- Reducing emissions by eliminating 100 percent of emissions from our New Mexico coal-fired generating facilities by the end of 2020 and from our Colorado coal-fired generating facilities by 2030.

- Increasing clean energy by bringing over 1 gigawatt of wind and solar resources online by 2024, meaning 50 percent of the energy consumed by our Members customers is expected to come from renewables by 2024.

- Increasing Member flexibility to develop more local, self-supplied renewable energy.

- Extending benefits of a clean grid across the economy through expanded 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 the first quarter of 2020, in accordance with accounting requirements, we will recognize a one-time impairment loss of approximately $282 million associated with the early retirement of Escalante Station. The shortened lives of Craig Station Units 2 and 3 increases annual depreciation expense in the amount of approximately $6.6 million and $21.1 million, respectively; however, such recovery of increased expense through rates is subject to approval by FERC. The shortened life of Colowyo Mine increases annual depreciation, amortization and depletion expense in the amount of approximately $12.7 million; however, such recovery of increased expense through rates is subject to approval by FERC.

In connection with such early retirements, our Board continues to evaluate the creation of regulatory assets and use of regulatory liabilities to ensure our 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.

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 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 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. Our DSR for the twelve months ended December 31, 2019 was 1.18. See Appendix A – Calculation of Financial Ratios.

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. As of December 31, 2019, our ECR was 25.45 percent. See Appendix A – Calculation of Financial Ratios.

As of December 31, 2019, we had approximately $2.8 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. Therefore, the details of the calculations are shown in Appendix A–Calculation of Financial Ratios.

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 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 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 $415.5 million of patronage capital to our members.

Pursuant to our Board Policy for Financial Goals and Capital Credits, we set rates to achieve a DSR and ECR in excess of the requirements under our Master Indenture in order to mitigate the risk of potential negative variances between budgeted margins and actual margins. This policy 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. In association with the above change, our Board Policy for Financial Goals and Capital Credits was also revised 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. The amount of cash our Board may internally restrict each year is not based upon the amount of revenue and income deferred. In connection with such policy, our Board has internally restricted cash in the amount of $25.5 million as of December 31, 2019. 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 entire balance of the restricted cash related to deferred revenue in response to volatile market conditions.

Rates and Regulation

At our July 2019 Board meeting, because of increased pressure by the states to regulate our rates and charges, our Board authorized us to take action to place us under wholesale rate regulation by FERC. By the addition of a non-cooperative member in 2019 and specifically by the addition of MIECO, Inc. as a member on September 3, 2019, we became FERC jurisdictional for our Member rates, transmission service, and our market based rates. During the week of December 23, 2019, we filed our tariff filings, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. We expect FERC to rule on their acceptance of these tariffs by the end of March 2020. See “BUSINESS – RATE REGULATION.”

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Revenues from electric power sales to our Members are primarily from our Class A wholesale rate schedule. Our Class A rate schedule for electric power sales to our Members consist of three billing components: an energy rate and two demand rates. 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 Members. Energy is the physical electricity delivered to our Members. In 2019 (A-40 rate), 2018 (A-40 rate), and 2017 (A-40 rate), our Class A wholesale rate schedules used the same rate design. 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 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. This rate structure was filed at FERC as a "stated rate" where we requested FERC to approve the existing rate as stated. However, upon our next rate change, we will be required to justify the new rate at FERC with a contested rate case. While our Board still has authority in determining our proper rates, those rates must be further approved by FERC subject to outside comments.

Approved by our Board in September 2019, the A-40 rate schedule will continue in effect for 2020 and that rate was filed at FERC on December 23, 2019 for acceptance by the end of March 2020.

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. However, in accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Under this regulatory accounting approach, any income tax expense or benefit on our consolidated statements of operation includes only the current portion.

Results of Operations

General

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

Weather has a significant effect on the usage of electricity by impacting both the electricity used per hour and the total peak demand for electricity. Consequently, weather has a significant impact on 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 Members' usage of electricity include:

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

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

Operating Revenues

Our operating revenues are primarily derived from electric power sales to our 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 2019 and 2018 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2019	2018	Amount	Percent
Operating revenues				
Member electric sales	$ 1,238,672	$ 1,235,872	$ 2,800	0.2%
Non-member electric sales	95,401	34,763	60,638	174.4%
Other	51,399	50,202	1,197	2.4%
Total operating revenues	$ 1,385,472	$ 1,320,837	$ 64,635	4.9%
Energy sales (in MWh):				
Member electric sales	16,412,525	16,384,415	28,110	0.2%
Non-member electric sales	1,701,476	1,811,482	(110,006)	(6.1)%
	18,114,001	18,195,897	(81,896)	(0.5)%

- 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 $6.2 million of previously deferred revenue during the twelve months ended December 31, 2019 compared to a revenue deferral of non-member electric sales of $51.7 million during the same period in 2018. Excluding the effect of these rate stabilization measures, non-member electric sales revenue increased $2.8 million, or 3.2 percent, to $89.2 million in 2019 compared to $86.4 million in 2018. Although non-member sales (in MWhs) decreased, the average non-member rate increased 9.9 percent during the twelve months ended December 31, 2019 compared to the same period in 2018.

Operating Expenses

Our operating expenses are primarily comprised of the costs that we incur to supply and transmit our 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 2019 and 2018 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2019	2018	Amount	Percent
Operating expenses				
Purchased power	$ 328,921	$ 343,509	$ (14,588)	(4.2)%
Fuel	280,325	237,721	42,604	17.9%
Production	209,586	212,917	(3,331)	(1.6)%
Transmission	163,757	161,652	2,105	1.3%
General and administrative	49,607	33,046	16,561	50.1%
Depreciation, amortization and depletion	157,734	154,975	2,759	1.8%
Coal mining	10,027	637	9,390	1,474.1%
Other	19,090	14,987	4,103	27.4%
Total operating expenses	$ 1,219,047	$ 1,159,444	$ 59,603	5.1%

- Purchase power expense decreased primarily due to energy demands being met by increased generation from our generating facilities. Purchased power decreased (in MWhs) 6.2 percent for the twelve months ended December 31, 2019 compared to the same period in 2018. This decrease was partially offset by a 2.2 percent increase in the average price of purchased power during the twelve months ended December 31, 2019 compared to the same period in 2018.
- Fuel expense includes coal, natural gas, and other fuel consumed at the generating stations. Fuel expense increased primarily due to greater generation from our generating facilities and increases in environmental reclamation and asset retirement obligations during the period. Net generation increased (in MWhs) 3.3 percent during the twelve months ended December 31, 2019 compared to the same period in 2018. The increase in generation is primarily attributable to the availability of Craig Station Unit 3 during the twelve months ended December 31, 2019. Craig Station experienced an unplanned maintenance outage that began in December 2017 and was brought back online in June 2018. Also included in fuel expense during the twelve months ended December 31, 2019 is 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. We continue to evaluate the New Horizon mine post reclamation obligation and will make adjustments as needed.
- General and administrative expense increased primarily due to an increase in outside professional services as well as an overall increase in expenses related to general and administration labor and benefits.
- Coal mining expense increased primarily due to costs to provide coal from the Colowyo Mine to third parties during the twelve months ended December 31, 2019. There were minimal third party sales of coal from the Colowyo Mine during the same period in 2018.

Other Income

Capital credits from cooperatives decreased $17.6 million, or 64.2 percent, to $9.8 million in 2019 compared to $27.4 million in 2018. The decrease was primarily due to a lower patronage allocation from Basin of $5.1 million during the twelve months ended December 31, 2019 compared to $21.4 million for the comparable period in 2018.

Other income increased $13.3 million, or 259.1 percent, to $18.4 million in 2019 compared to $5.1 million in 2018. The increase 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. The decision reduces the royalty rate from 12.5 percent to 8 percent for coal extracted under certain leases from September 1, 2015 through June 30, 2019.

Year ended December 31, 2018 compared to year ended December 31, 2017

Operating Revenues

The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for 2018 and 2017 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2018	2017	Amount	Percent
Operating revenues				
Member electric sales	$ 1,235,872	$ 1,199,940	$ 35,932	3.0%
Non-member electric sales	34,763	98,872	(64,109)	(64.8)%
Other	50,202	89,781	(39,579)	(44.1)%
Total operating revenues	$ 1,320,837	$ 1,388,593	$ (67,756)	(4.9)%
Energy sales (in MWh):				
Member electric sales	16,384,415	15,905,656	478,759	3.0%
Non-member electric sales	1,811,482	2,113,011	(301,529)	(14.3)%
	18,195,897	18,018,667	177,230	1.0%

- Member electric sales revenue increased primarily due to increases in industrial loads and overall customer growth in our Members' service territories.
- Non-member electric sales revenue decreased primarily due to the deferral of $51.7 million of non-member sales in accordance with our Board Policy for Financial Goals and Capital Credits during 2018. Excluding the effect of the recognition of $5.5 million of previously deferred non-member electric sales revenue in 2017 and the deferral of $51.7 million of non-member electric sales recognition in 2018, non-member electric sales revenue decreased $7.0 million, or 7.5 percent, to $86.4 million in 2018 compared to $93.4 million in 2017. The decrease in MWhs sold and non-member electric sales revenue was primarily due to the expiration of long-term power sales arrangements in 2017, partially offset by an increase in short-term market sales and higher average market rates during 2018.

Operating Expenses

The following is a summary of the components of our operating expenses for 2018 and 2017 (dollars in thousands):

	Year Ended December 31,		Period-to-period Change	
	2018	2017	Amount	Percent
Operating expenses				
Purchased power	$ 343,509	$ 339,830	$ 3,679	1.1%
Fuel	237,721	244,328	(6,607)	(2.7)%
Production	212,917	207,993	4,924	2.4%
Transmission	161,652	153,510	8,142	5.3%
General and administrative	33,046	28,704	4,342	15.1%
Depreciation, amortization and depletion	154,975	174,526	(19,551)	(11.2)%
Coal mining	637	40,034	(39,397)	(98.4)%
Other	14,987	15,971	(984)	(6.2)%
Total operating expenses	$ 1,159,444	$ 1,204,896	$ (45,452)	(3.8)%

- Transmission expense increased primarily due to the recognition of a $7.75 million reduction in transmission expense during the first quarter of 2017 related to the TEP transmission services agreement settlement.
- Depreciation, amortization and depletion expense decreased primarily due to the retirement of the San Juan Generating Station during the fourth quarter of 2017 and accelerated depreciation recognized at New Horizon Mine during 2017. Depreciation expense decreased $10.6 million in 2018 as a result of San Juan Generating Station being fully depreciated as of December 31, 2017. Depreciation expense decreased $5.5 million in 2018 as a result of the New Horizon Mine accelerated depreciation recognized during 2017.
- Coal mining expense decreased primarily due to a contract that ended in December 2017 to sell coal from the Colowyo Mine to the other joint owners in the Yampa Project.

Other Income

Capital credits from cooperatives increased $14.5 million, or 111.6 percent, to $27.4 million in 2018 compared to $12.9 million in 2017. The increase was primarily due to a patronage allocation from Basin of $21.4 million during the twelve months ended December 31, 2018 compared to $7.1 million for the comparable period in 2017.

Financial Condition as of December 31, 2019 compared to December 31, 2018

Assets

Construction work in progress decreased $42.8 million, or 20.6 percent, to $164.9 million as of December 31, 2019 compared to $207.7 million as of December 31, 2018. The decrease was primarily due to transfers to electric plant in service for completed projects of $218.9 million (primarily for the completion of an environmental upgrade project at Laramie River Station and completion of various transmission projects) partially offset by capital expenditures of $176.1 million (primarily for an environmental upgrade project at the Laramie River Station, a turbine overhaul project at the J.M. Shafer Generating Station, and various transmission improvements and system upgrades).

Other plant consists of mine assets and non-utility assets (which consist of piping and equipment specifically related to providing steam and water from the Escalante Station to a third party for the use in the production of paper). Other plant increased $24.4 million, or 7.4 percent, to $409.1 million as of December 31, 2019 compared to $384.7 million as of December 31, 2018. The increase was primarily due to capital expenditures for the development of the Collom mining pit at the Colowyo Mine.

Cash and cash equivalents decreased $33.8 million, or 28.9 percent, to $83.1 million as of December 31, 2019 compared to $116.9 million as of December 31, 2018. The decrease was primarily due to proceeds from the issuance of long-term debt, principal payments of long-term debt, and patronage capital retirements to our members. These decreases were partially offset by short-term borrowings to fund our capital expenditures and working capital requirements, and the collection of insurance recoveries.

Restricted cash and investments-noncurrent increased $19.9 million, or 129.5 percent, to $30.5 million as of December 31, 2019 compared to $10.6 million as of December 31, 2018. The increase was primarily due to restricting cash related to deferred revenues. Our Board, in accordance with our Board Policy for Financial Goals and Capital Credits, has internally restricted cash in the amount of $25.5 million and $4.6 million as of December 31, 2019 and December 31, 2018, respectively.

Regulatory assets increased $59.9 million, or 13.7 percent, to $497.3 million as of December 31, 2019 compared to $437.4 million as of December 31, 2018. The increase was primarily due to the deferral of the $37.1 million impairment loss related to the closure of the Nucla Generating Station in September 2019. The deferred impairment loss is being amortized to depreciation, amortization and depletion expense over the 3.3-year period ending in December 2022 and recovered from our Members in rates. Also, we established a valuation allowance of $30.5 million because it is more likely than not that some of the benefit from the federal and state net operating losses will not be realized in the future. The valuation allowance increased the regulatory asset associated with deferred income taxes.

Equity and Liabilities

Patronage capital equity increased $15.3 million to $1.031 billion as of December 31, 2019 compared to $1.016 billion as of December 31, 2018. The increase was due to a margin attributable to us from our members of $45.3 million partially offset by 2019 patronage capital retirements to our members of $30.0 million.

Long-term debt decreased $46.0 million to $3.063 billion as of December 31, 2019 compared to $3.109 billion as of December 31, 2018 and current maturities of long-term debt decreased $14.2 million, or 14.8 percent, to $81.6 million as of December 31, 2019 compared to $95.8 million as of December 31, 2018. The total decrease of $60.2 million was primarily due to debt payments of $96.1 million (primarily $49.1 million for the First Mortgage Obligations, Series 2009C, and $33.8 million for the Springerville certificates) partially offset by debt proceeds of $34.9 million.

Short-term borrowings increased $48.2 million, or 23.6 percent, to $252.3 million as of December 31, 2019 compared to $204.1 million as of December 31, 2018. Short-term borrowings consist of our commercial paper program that provides an additional financing source for our short-term liquidity needs. The increase was due to net additional commercial paper issued between January 1, 2019 and December 31, 2019 to fund capital expenditures and working capital requirements.

Regulatory liabilities decreased $15.2 million, or 11.1 percent, to $122.2 million as of December 31, 2019 compared to $137.4 million as of December 31, 2018. The decrease was primarily due to the recognition of $6.2 million of previously deferred non-member electric sales revenues and the June 2019 settlement of an interest rate swap of $8.6 million. The interest rate swap was terminated with no associated debt issuance and no gain or loss was realized on our consolidated statements of operations.

Asset retirement obligations increased $21.9 million, or 40.1 percent, to $76.5 million as of December 31, 2019 compared to $54.6 million as of December 31, 2018. The increase was primarily due to an increased environmental reclamation obligation of $22.4 million for the 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 New Horizon mine post reclamation obligation and will make adjustments to the obligation as needed.

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, 2019, we had $83.1 million in cash and cash equivalents. Our committed credit arrangement as of December 31, 2019 is as follows (dollars in thousands):

	Authorized Amount	Available December 31, 2019
Revolving Credit Agreement	$ 650,000 (1)	$ 397,000 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.
(2) The portion of this facility that was unavailable at December 31, 2019 was $253 million which was dedicated to support outstanding commercial paper.

We have a secured Revolving Credit Agreement with aggregate commitments of $650 million with CFC, as administrative agent. 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 $247 million of the commercial paper back-up sublimit remained available as of December 31, 2019. As of December 31, 2019, we had $397 million of availability under the Revolving Credit Agreement.

The Revolving Credit Agreement is secured under the Master Indenture and has a maturity date of April 25, 2023, unless extended as provided therein. 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 at December 31, 2019.

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, 2019, thereby providing 100 percent dedicated support for any commercial paper outstanding. We had $253 million of commercial paper outstanding (prior to netting discounts) at December 31, 2019.

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, 2019 compared to year ended December 31, 2018

Operating activities. Net cash provided by operating activities was $233.3 million in 2019 compared to $216.3 million in 2018, an increase of $17.0 million. The increase in cash provided by operating activities in 2019 compared to 2018 was primarily impacted by a decrease in coal inventory (due to lower coal production tons at the Colowyo Mine), a decrease in accounts receivable related to the settlement of insurance recoveries, and the timing of payment of trade payables and accrued expenses.

Investing activities. Net cash used in investing activities was $203.4 million in 2019 compared to $282.8 million in 2018, a decrease of $79.4 million. The decrease was primarily due to lower capital expenditures in 2019 compared to 2018 for the development of the Collom mining pit at the Colowyo Mine.

Financing activities. Net cash used in financing activities was $43.7 million in 2019 compared to net cash provided by financing activities of $43.2 million in 2018, an increase in net cash used in financing activities of $86.9 million. The increase in net cash used in financing activities in 2019 compared to 2018 was primarily due to lower net borrowings of $104.5 million, a decrease of $11.3 million in short-term borrowing activity to fund capital expenditure and working capital requirements, and higher patronage capital retirements of $8.0 million. These increases in net cash used in financing activities were partially offset by lower principal payments of long-term debt of

$37.7 million in 2019 compared to 2018 (primarily $57.2 million of lower principal payments for various CoBank and CFC debt partially offset by $20.1 million of higher principal payments for the Springerville certificates).

Year ended December 31, 2018 compared to year ended December 31, 2017

Operating activities. Net cash provided by operating activities was $216.3 million in 2018 compared to $240.4 million in 2017, a decrease of $24.1 million. The decrease in cash provided by operating activities in 2018 compared to 2017 was primarily due to an increase in coal inventory and an increase in purchased power expense (due to higher renewable energy purchases).

Investing activities. Net cash used in investing activities was $282.8 million in 2018 compared to $212.8 million in 2017, an increase of $70.0 million. The increase was primarily due to higher capital expenditures for generation and transmission improvements and system upgrades and the development of the Collom mining pit at the Colowyo Mine.

Financing activities. Net cash provided by financing activities was $43.2 million in 2018 compared to net cash used in financing activities of $44.6 million in 2017, an increase of $87.8 million. The increase in net cash provided by financing activities in 2018 compared to 2017 was primarily due to debt proceeds of $90.1 million from CoBank in December 2018 and an increase of $34.7 million in short-term borrowings due to additional commercial paper issued between January 1, 2018 and December 31, 2018 to fund capital expenditures and working capital requirements. These increases were partially offset by higher principal payments of long-term debt during 2018.

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 2020 through 2024, we forecast that we may invest approximately $877 million in new facilities and upgrades to our existing facilities. Our investment forecast for new facilities and upgrades to existing facilities by capital expenditure category is as follows (dollars in thousands):

	2020	2021	2022	2023	2024	Total
Generation	$ 33,439	$ 71,768	$ 50,376	$ 28,534	$ 20,192	$ 204,309
Transmission	135,120	113,012	113,568	76,453	44,079	482,232
General Plant	33,498	33,003	38,402	36,297	26,666	167,866
Other (1)	18,890	337	1,287	770	1,012	22,296
Total Capital Expenditures by Category	$ 220,947	$ 218,120	$ 203,633	$ 142,054	$ 91,949	$ 876,703

(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, 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. 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. See “BUSINESS – ENVIRONMENTAL REGULATION” and “RISK FACTORS.”

Capital projects include several transmission projects to improve reliability and load-serving capability throughout our service area and development of the Collom mining pit at the Colowyo Mine.

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, 2019 (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)	$ 3,144,906	$ 81,555	$ 180,840	$ 379,341	$ 2,503,170
Interest (2)	2,305,420	146,328	277,109	258,234	1,623,749
Operating Lease Obligations	7,867	5,660	836	515	856
Construction Obligations	63,279	43,658	19,621	—	—
Coal Purchase Obligations	333,064	91,173	76,605	15,177	150,109
Total	$ 5,854,536	$ 368,374	$ 555,011	$ 653,267	$ 4,277,884

(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 $528 million of variable rate long-term debt. Future variable rates are based on Bloomberg surveys and internal forecasts as of December 31, 2019.

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, 2019, we had $3.4 billion in outstanding obligations, including approximately $2.8 billion of debt outstanding secured on a parity basis under our Master Indenture, $253.0 million in short term borrowings, one unsecured loan agreement totaling $27.1 million and the Springerville certificates totaling $371.2 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 $247 million of the commercial paper back-up sublimit remained available as of December 31, 2019. As of December 31, 2019, we had $397 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 and the Collom mining pit at Colowyo Mine.

Coal Purchase Obligations. We have commitments to purchase coal for our generating facilities under long-term contracts that expire between 2020 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- (negative outlook)” by S&P, and “A (negative 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, 2019 and 2018 are as follows:

	December 31, 2019		December 31, 2018	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,166,472	$ 3,608,341	$ 3,227,663	$ 3,421,753

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 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 coal-fired generating facilities.

We have available for our use approximately 440 MWs of simple-cycle turbine capacity that is capable of operation 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 Members. In 2019, these resources provided approximately 5.3 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, 2019, we were exposed to the risk of changes in interest rates related to our $527.7 million of variable rate debt, including $253.0 million of short-term borrowings, $102.7 million of variable rate CFC notes and $172.0 million of variable rate CoBank notes. The total variable debt balance consists of $274.3 million of LIBOR based loans. As of December 31, 2019, the weighted average interest rate on this variable rate debt was 2.63 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, 2019, we had 15.4 percent of our total debt in a variable rate mode. An increase in interest rates of 100 basis points would increase our annual debt service by approximately $5.3 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, 2019 and 2018, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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.

/s/ Ernst & Young LLP

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

Denver, Colorado
March 12, 2020

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

As of December 31,	2019	2018
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 6,090,392	$ 5,899,128
Construction work in progress	164,924	207,732
Total electric plant	6,255,316	6,106,860
Less allowances for depreciation and amortization	(2,641,470)	(2,499,376)
Net electric plant	3,613,846	3,607,484
Other plant	409,051	384,650
Less allowances for depreciation, amortization and depletion	(113,607)	(110,939)
Net other plant	295,444	273,711
Total property, plant and equipment	3,909,290	3,881,195
Other assets and investments		
Investments in other associations	161,945	161,487
Investments in and advances to coal mines	19,681	18,928
Restricted cash and investments	30,516	10,606
Intangible assets, net of accumulated amortization	—	3,662
Other noncurrent assets	8,654	9,022
Total other assets and investments	220,796	203,705
Current assets		
Cash and cash equivalents	83,070	116,858
Restricted cash and investments	182	126
Deposits and advances	28,434	29,641
Accounts receivable—Members	105,371	107,572
Other accounts receivable	28,039	22,434
Coal inventory	50,191	55,883
Materials and supplies	93,632	93,786
Total current assets	388,919	426,300
Deferred charges		
Regulatory assets	497,279	437,377
Prepayment—NRECA Retirement Security Plan	26,862	31,837
Other	42,672	46,453
Total deferred charges	566,813	515,667
Total assets	**$ 5,085,818**	**$ 5,026,867**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 1,031,063	$ 1,015,754
Accumulated other comprehensive income (loss)	(1,518)	375
Noncontrolling interest	111,717	110,169
Total equity	1,141,262	1,126,298
Long-term debt	3,063,351	3,109,301
Total capitalization	4,204,613	4,235,599
Current liabilities		
Member advances	18,025	13,988
Accounts payable	99,033	105,009
Short-term borrowings	252,323	204,145
Accrued expenses	43,761	40,285
Current asset retirement obligations	2,460	2,183
Accrued interest	29,716	32,070
Accrued property taxes	29,129	28,582
Current maturities of long-term debt	81,555	95,757
Total current liabilities	556,002	522,019
Deferred credits and other liabilities		
Regulatory liabilities	122,169	137,369
Deferred income tax liability	58,937	18,098
Asset retirement and environmental reclamation obligations	76,454	54,589
Other	56,399	50,266
Total deferred credits and other liabilities	313,959	260,322
Accumulated postretirement benefit and postemployment obligations	11,244	8,927
Total equity and liabilities	**$ 5,085,818**	**$ 5,026,867**

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,	2019	2018	2017
Operating revenues			
Member electric sales	$ 1,238,672	$ 1,235,872	$ 1,199,940
Non-member electric sales	95,401	34,763	98,872
Other	51,399	50,202	89,781
	1,385,472	1,320,837	1,388,593
Operating expenses			
Purchased power	328,921	343,509	339,830
Fuel	280,325	237,721	244,328
Production	209,586	212,917	207,993
Transmission	163,757	161,652	153,510
General and administrative	49,607	33,046	28,704
Depreciation, amortization and depletion	157,734	154,975	174,526
Coal mining	10,027	637	40,034
Other	19,090	14,987	15,971
	1,219,047	1,159,444	1,204,896
Operating margins	**166,425**	**161,393**	**183,697**
Other income			
Interest	6,175	5,294	4,723
Capital credits from cooperatives	9,799	27,373	12,934
Membership withdrawal	—	—	5,000
Other	18,427	5,131	3,966
	34,401	37,798	26,623
Interest expense, net of amounts capitalized	151,470	153,704	147,608
Income tax benefit	(307)	(534)	(1,092)
Net margins including noncontrolling interest	49,663	46,021	63,804
Net margin attributable to noncontrolling interest	(4,354)	(3,287)	(2,148)
Net margins attributable to the Association	**$ 45,309**	**$ 42,734**	**$ 61,656**

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,	2019	2018	2017
Net margins including noncontrolling interest	$ 49,663	$ 46,021	$ 63,804
Other comprehensive income (loss):			
Unrealized gain on securities available for sale	—	—	43
Unrecognized actuarial gain (loss) on postretirement benefit obligation	(1,341)	456	106
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	(338)	288	(73)
Unrecognized prior service cost (credit)	(214)	—	—
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	(1,893)	585	76
Comprehensive income including noncontrolling interest	47,770	46,606	63,880
Net comprehensive income attributable to noncontrolling interest	(4,354)	(3,287)	(2,148)
Comprehensive income attributable to the Association	**$ 43,416**	**$ 43,319**	**$ 61,732**

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,	2019	2018	2017
Patronage capital equity at beginning of period	$ 1,015,754	$ 1,003,020	$ 961,364
Net margins attributable to the Association	45,309	42,734	61,656
Retirement of patronage capital	(30,000)	(30,000)	(20,000)
Patronage capital equity at end of period	**1,031,063**	**1,015,754**	**1,003,020**
Accumulated other comprehensive income (loss) at beginning of period	375	(210)	(286)
Unrealized gain on securities available for sale	—	—	43
Unrecognized actuarial gain (loss) on postretirement benefit obligation	(1,341)	456	106
Reclassification adjustment for unrealized gain on securities available for sale included in net margin	—	(159)	—
Reclassification adjustment for acturarial (gain) loss on postretirement benefit obligation included in net margin	(338)	288	(73)
Unrecognized prior service cost	(214)	—	—
Accumulated other comprehensive income (loss) at end of year	**(1,518)**	**375**	**(210)**
Noncontrolling interest at beginning of year	110,169	111,295	109,147
Net comprehensive income attributable to noncontrolling interest	4,354	3,287	2,148
Equity distribution to noncontrolling interest	(2,806)	(4,413)	—
Noncontrolling interest at end of year	**111,717**	**110,169**	**111,295**
Total equity at end of year	**$ 1,141,262**	**$ 1,126,298**	**$ 1,114,105**

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,	2019	2018	2017
Operating activities			
Net margins including noncontrolling interest	$ 49,663	$ 46,021	$ 63,804
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	157,734	154,975	174,526
Amortization of intangible asset	3,662	7,324	7,324
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,372
Amortization of debt issuance costs	2,375	2,641	1,985
Impairment loss	37,067	—	93,494
Deferred impairment loss	(37,067)	—	(93,494)
Recognition of deferred membership withdrawal income	—	—	(5,000)
Deferred revenue	—	51,679	9,527
Recognition of deferred revenue	(6,153)	—	(15,000)
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,276)	(18,090)	(4,417)
Proceeds from settlement of interest rate swap	—	—	4,625
Changes in operating assets and liabilities:			
Accounts receivable	2,383	(5,922)	4,924
Coal inventory	5,692	(8,080)	17,097
Materials and supplies	154	(3,576)	(1,691)
Accounts payable and accrued expenses	1,136	(10,434)	628
Accrued interest	(2,354)	(782)	(1,313)
Accrued property taxes	547	1,446	(448)
Other deferred credits - TEP transmission settlement	—	—	(15,521)
Other	14,328	(6,297)	(6,039)
Net cash provided by operating activities	**233,263**	**216,277**	**240,383**
Investing activities			
Purchases of plant	(212,815)	(280,712)	(214,781)
Changes in deferred charges	9,347	(2,233)	1,112
Proceeds from other investments	65	67	911
Net cash used in investing activities	**(203,403)**	**(282,878)**	**(212,758)**
Financing activities			
Changes in Member advances	(4,177)	(1,717)	(6,852)
Payments of long-term debt	(96,099)	(133,848)	(108,301)
Proceeds from issuance of long-term debt	34,910	150,090	60,000
Debt issuance costs	(13)	(10,697)	(1,450)
Increase in short-term borrowings, net	48,178	59,478	24,767
Retirement of patronage capital	(23,303)	(15,339)	(12,815)
Equity distribution to noncontrolling interest	(2,806)	(4,413)	—
Other	(372)	(328)	101
Net cash provided by (used in) financing activities	**(43,682)**	**43,226**	**(44,550)**
Net decrease in cash, cash equivalents and restricted cash and investments	**(13,822)**	**(23,375)**	**(16,925)**
Cash, cash equivalents and restricted cash and investments – beginning	**127,590**	**150,965**	**167,890**
Cash, cash equivalents and restricted cash and investments – ending	**$ 113,768**	**$ 127,590**	**$ 150,965**
Supplemental cash flow information:			
Cash paid for interest	$ 161,460	$ 161,809	$ 159,112
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ (96)	$ (44)	$ (3,242)

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 two classes of members – all requirements electric members known as our Class A members and non-utility members. For our Class A members, we provide electric power to our forty-three electric member distribution systems ("Member(s)") pursuant to long-term wholesale electric service contracts. We have three non-utility members. The addition of non-utility members in 2019 and specifically the addition of MIECO, Inc. on September 3, 2019 removed the exemption from Federal Energy Regulatory Commission's ("FERC") regulation for us, thus subjecting us to full rate and transmission jurisdiction by FERC on September 3, 2019.

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 2019, 2018 and 2017, total megawatt-hours sold were 18.1, 18.2 and 18.0 million, respectively, of which 90.6, 90.0 and 88.3 percent, respectively, were sold to Members. Total revenue from electric sales was $1.3 billion for 2019, 2018 and 2017 of which 92.8, 97.3, and 92.3 percent in 2019, 2018 and 2017, respectively, was from Member sales. Energy resources were provided by our generation and purchased power, of which 61.5, 58.9 and 61.4 percent in 2019, 2018 and 2017, respectively, were from our generation.

Revenue from one Member, United Power, Inc., was $205.5 million, or 16.6 percent, of our Member revenue and 14.8 percent of our total operating revenues in 2019. No other Member exceeded 10 percent of our Member revenue or our total operating revenues in 2019.

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

We, including our subsidiaries, employ 1,467 people, of which 280 are subject to collective bargaining agreements. None of these agreements expire within one year.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF CONSOLIDATION: Our consolidated financial statements include the accounts of the Association, our wholly-owned and majority-owned subsidiaries, and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 14—Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities.

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

JOINTLY OWNED FACILITIES: We own undivided interests in two jointly owned generating facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Yampa Project (operated by us) and the Missouri Basin Power Project

("MBPP") (operated by Basin Electric Power Cooperative ("Basin")). Each participant in these agreements receives a portion of the total output of the generation facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and operating expenses is included in our consolidated financial statements. See Note 3 – Property, Plant and Equipment.

SEGMENT REPORTING: We are organized for the purpose of supplying wholesale power to our Members and do so through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. In support of our coal-fired generating resources, we have direct ownership 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 2019, we recognized an impairment loss of $37.1 million associated with the early retirement of Nucla Generating Station, and in 2017, we determined that the $93.5 million of development costs (which excluded the costs of land and water rights) for a new coal-fired generating unit or units at Holcomb Generating Station were impaired. These impairment losses were deferred in accordance with the accounting requirements related to regulated operations at the discretion of our Board. 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 and investments in coal mines, 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 it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from our 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 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. 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 revenues, other income, or a reduction in expense concurrent with their recovery in rates.

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

	December 31, **2019**	December 31, **2018**
Regulatory assets		
Deferred income tax expense (1)	$ 58,937	$ 18,098
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	83,714	86,005
Goodwill – J.M. Shafer (3)	49,145	51,994
Goodwill – Colowyo Coal (4)	37,194	38,227
Deferred debt prepayment transaction costs (5)	140,931	149,559
Deferred Holcomb expansion impairment loss (6)	93,494	93,494
Deferred Nucla impairment loss (7)	33,864	—
Total regulatory assets	497,279	437,377
Regulatory liabilities		
Interest rate swap - unrealized gain (8)	—	8,576
Interest rate swap - realized gain (9)	3,744	4,215
Deferred revenues (10)	75,853	82,006
Membership withdrawal (11)	42,572	42,572
Total regulatory liabilities	122,169	137,369
Net regulatory asset	$ 375,110	$ 300,008

(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 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 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 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 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. Beginning January 2020, the deferred impairment loss is expected to be 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 Members in rates.

(7) In July 2019, the 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, 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 is being amortized to depreciation, amortization and depletion expense over the 3.3-year period ending in December 2022 and recovered from our Members in rates.

(8) Represented deferral of an unrealized gain related to the change in fair value of a forward starting interest rate swap that was entered into in 2016 in order to hedge interest rates on anticipated future borrowings. This interest rate swap was terminated in June 2019 with no gain or loss being realized.

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

(10) Represents deferral of the recognition of non-member electric sales revenues. These deferred non-member electric sales revenues will be refunded to Members through reduced rates when recognized in non-member electric sales revenue in future periods.

(11) Represents the deferral of the recognition of other income recorded in connection with the withdrawal of a former member from membership in us. This deferred membership withdrawal income will be refunded to 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 of 4.7 percent were used for 2019, 2018 and 2017. The amount of interest capitalized during construction was $8.7, $8.6 and $11.0 million during 2019, 2018 and 2017, 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, **2019**	December 31, **2018**
Basin Electric Power Cooperative	$ 117,368	$ 118,115
National Rural Utilities Cooperative Finance Corporation - patronage capital	11,761	11,704
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,953	16,018
CoBank, ACB	10,201	9,062
Western Fuels Association, Inc.	2,409	2,392
Other	4,253	4,196
Investments in other associations	$ 161,945	$ 161,487

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 2019, 2018 or 2017.

INVESTMENTS IN AND ADVANCES TO COAL MINES: We have direct ownership and investments in coal mines to support our coal-fired generating facilities. We, and certain participants in the Yampa Project, are members 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. Our investment in Trapper Mining is recorded using the equity method. In addition, we have 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). 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, **2019**	December 31, **2018**
Investment in Trapper Mine	$ 15,881	$ 15,350
Advances to Dry Fork Mine	3,800	3,578
Investments in and advances to coal mines	$ 19,681	$ 18,928

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, 2019	December 31, 2018
Cash and cash equivalents	$ 83,070	$ 116,858
Restricted cash and investments - current	182	126
Restricted cash and investments - noncurrent	30,516	10,606
Cash, cash equivalents and restricted cash and investments	$ 113,768	$ 127,590

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 and $4.6 million as of December 31, 2019 and December 31, 2018, respectively, which is 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 entire balance of the restricted cash related to deferred revenue 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, 2019, the cost and estimated fair value of the investments were $0.7 million. At December 31, 2018, the cost and estimated fair value of the investments were $0.8 and $0.7 million, respectively.

INVENTORIES: Coal inventories at our owned generating facilities are stated at LIFO (last-in, first-out) cost and were $21.4 and $24.6 million as of December 31, 2019 and 2018, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2019, we realized lower coal fuel expense of $0.5 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 Members in rates subject to approval by our Board, which has budgetary and rate-setting authority, 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.

We had entered into a forward starting interest rate swap to hedge a portion of our future long-term debt interest rate exposure. The unrealized gain of $8.6 million as of December 31, 2018 was deferred in accordance with accounting related to regulated operations. This interest rate swap was terminated in June 2019 with no gain or loss being realized. See Note 2 – Accounting for Rate Regulation.

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

	December 31, 2019	December 31, 2018
Preliminary surveys and investigations	$ 21,261	$ 20,660
Advances to operating agents of jointly owned facilities	3,917	13,161
Interest rate swap	—	8,576
Operating lease right-of-use assets	7,622	—
Other	9,872	4,056
Total other deferred charges	$ 42,672	$ 46,453

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. 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. These liabilities are included in asset retirement obligations.

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.

Coal mines: We have asset retirement obligations for the final reclamation costs and environmental obligations for post-reclamation monitoring related to the Colowyo Mine, the New Horizon Mine, and the Fort Union 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):

	2019	2018
Obligations at beginning of period	$ 56,772	$ 56,855
Liabilities incurred	23,290	6,065
Liabilities settled	(1,090)	(5,475)
Accretion expense	2,863	2,458
Change in cash flow estimate	(2,921)	(3,131)
Total obligations at end of period	$ 78,914	$ 56,772
Less current obligations at end of period	(2,460)	(2,183)
Long-term obligations at end of period	$ 76,454	$ 54,589

We recorded an additional environmental 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 New Horizon mine post reclamation obligation and will make adjustments to the obligation 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.

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 $31.2 million for these easements from 2020 through the individual easement terms ending between 2036 and 2040. The present value of the remaining easement payments was $20.5 and $21.0 million as of December 31, 2019 and December 31, 2018, 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, **2019**	December 31, **2018**
Transmission easements	$ 20,549	$ 20,966
Operating lease liabilities - noncurrent	1,846	—
Contract liabilities (unearned revenue) - noncurrent	4,217	4,592
Customer deposits	3,015	2,458
Financial liabilities - reclamation	12,091	4,938
Other	14,681	17,312
Total other deferred credits and other liabilities	$ 56,399	$ 50,266

PATRONAGE CAPITAL: Our net margins are treated as advances of capital from our members and are allocated to our 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, depreciation, amortization, and depletion and interest 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. However, in accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current provision. 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 $1.6 and $2.3 million at December 31, 2019 and 2018, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was an expense of $0.6 million in 2018 and a credit of $0.4 million in 2019 and 2017.

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, 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, 2018, 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 %	$ 3,601,911	$ (1,504,802)	$ 2,097,109
Transmission plant	1.11 %	to	2.09 %	1,556,860	(562,216)	994,644
General plant	1.46 %	to	9.53 %	492,991	(316,233)	176,758
Other	2.75 %	to	10.00 %	247,366	(116,125)	131,241
Electric plant in service (at cost)				$ 5,899,128	$ (2,499,376)	3,399,752
Construction work in progress						207,732
Electric plant						$ 3,607,484

At December 31, 2019, we had $63.3 million of commitments to complete construction projects, of which approximately $43.7, $18.6 and $1.0 million are expected to be incurred in 2020, 2021 and 2022, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2019 (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 %	$ 396,292	$ 245,723	$ 21
MBPP - Laramie River Station	27.13 %	490,156	298,465	1,491
Total		$ 886,448	$ 544,188	$ 1,512

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. We also own a 50 percent undivided ownership in the land and the rights to mine the property known as Fort Union Mine. 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, **2019**	December 31, **2018**
Colowyo Mine assets	$ 356,612	$ 326,838
New Horizon Mine assets	38,949	44,589
Fort Union Mine assets	846	846
Accumulated depreciation and depletion	(106,337)	(104,031)
Net mine assets	290,070	268,242
Non-utility assets	12,644	12,377
Accumulated depreciation	(7,270)	(6,908)
Net non-utility assets	5,374	5,469
Net other plant	$ 295,444	$ 273,711

NOTE 4 – INTANGIBLE ASSETS

The December 2011 acquisition of TCP resulted in recording an intangible asset in the amount of $55.5 million related to a contractual obligation that TCP had to a third party under a purchase power agreement. The $55.5 million intangible asset represented the amount that the purchase power agreement contract terms were above market value at the acquisition date and was being amortized on a straight-line basis over the remaining life of the purchase power agreement through June 30, 2019. The straight-line method was consistent with the terms of the purchase power agreement as this contract was for a fixed amount of capacity at a fixed capacity rate that stayed constant over the term of the contract. The purchase power agreement intangible asset was amortized to other operating income as a reduction of the revenue generated by the purchase power agreement in the amount of $7.3 million in each of the years 2018 and

2017. The remaining $3.7 million was amortized to other operating income for the six-month period ending June 30, 2019.

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, 2019 and December 31, 2018.

Accounts Receivable

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

Contract liabilities (unearned revenue)

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. We recognized $0.7 million of this unearned revenue in 2019 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, **2019**	December 31, **2018**
Accounts receivable - Members	$ 105,371	$ 107,572
Other accounts receivable - trade:		
Non-member electric sales	4,727	6,998
Other	20,628	6,006
Total other accounts receivable - trade	25,355	13,004
Other accounts receivable - nontrade	2,684	9,430
Total other accounts receivable	$ 28,039	$ 22,434
Contract liabilities (unearned revenue)	$ 7,041	$ 7,906

NOTE 6 – LONG-TERM DEBT

We have $3.1 billion of long term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture") except for one unsecured note in the aggregate amount of $27.1 million as of December 31, 2019. 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, 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, 2019. As of December 31, 2019, we had $397 million in availability (including $247 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

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

	December 31, **2019**	December 31, **2018**
Mortgage notes payable		
3.66% to 8.08% CFC, due through 2028	$ 73,859	$ 77,085
2.63% to 4.43% CoBank, ACB, due through 2042	235,900	245,787
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 1, 6.00%, due through 2019	—	27,143
First Mortgage Obligations, Series 2009C, Tranche 2, 6.31%, due through 2021	44,000	66,000
Variable rate CFC, as determined by CFC, due through 2026	443	498
Variable rate CFC, LIBOR-based term loan, due through 2049	102,220	102,220
Variable rate CoBank, ACB, LIBOR-based term loans, due through 2044	172,039	137,130
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	371,211	405,000
Total debt	$ 3,166,472	$ 3,227,663
Less debt issuance costs	(27,412)	(29,775)
Less debt discounts	(9,906)	(10,139)
Plus debt premiums	15,752	17,309
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,144,906	$ 3,205,058
Less current maturities	(81,555)	(95,757)
Long-term debt	$ 3,063,351	$ 3,109,301

Annual maturities of total debt adjusted for debt issuance costs, discounts and premiums at December 31, 2019 are as follows (dollars in thousands):

2020	$ 81,555
2021	87,697
2022	93,143
2023	73,184
2024 (1)	306,157
Thereafter	2,503,170
	$ 3,144,906

(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):

	2019	2018
Commercial paper outstanding, net of discounts	$ 252,323	$ 204,145
Weighted average interest rate	1.88 %	2.65 %

At December 31, 2019, $247 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, 2019		December 31, 2018	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 715	$ 654	$ 818	$ 712

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 $79.0 million and $107.2 million as of December 31, 2019 and 2018, 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, 2019		December 31, 2018	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,166,472	$ 3,608,341	$ 3,227,663	$ 3,421,753

NOTE 9 – INCOME TAXES

We had an income tax benefit of $0.3 million, $0.5 million and $1.1 million in 2019, 2018 and 2017, 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. Under the liability method, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and for income tax purposes. In accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current portion. FERC may require us to change our regulatory accounting treatment.

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

	December 31, **2019**	December 31, **2018**
Deferred tax assets		
Safe harbor lease receivables	$ 14,552	$ 17,067
Net operating loss carryforwards	116,797	100,565
Alternative minimum tax credit carryforwards	308	615
Deferred revenues and membership withdrawal	28,185	29,650
Operating lease liabilities	131,817	—
Other	26,587	22,483
	318,246	170,380
Less valuation allowance	(30,468)	—
	287,778	170,380
Deferred tax liabilities		
Basis differences- property, plant and equipment	129,427	115,887
Capital credits from other associations	32,789	32,689
Deferred debt prepayment transaction costs	33,542	35,595
Operating lease right-of-use assets	136,930	—
Other	14,027	4,307
	346,715	188,478
Net deferred tax liability	$ (58,937)	$ (18,098)

The $40.8. million increase in net deferred tax liabilities is not recognized as a tax expense in 2019 due to our regulatory accounting treatment of deferred taxes. Instead, the tax expense is deferred and reflected as an increase in the regulatory asset established for deferred income tax expense. This liability method is included in our FERC rate filing, however, FERC may require a different method for the rate recovery of income taxes. 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 $58.9 and $18.1 million at December 31, 2019 and 2018, respectively.

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

	2019	**2018**	**2017**
Federal income tax expense at statutory rate	21.00 %	21.00 %	35.00 %
State income tax expense, net of federal benefit	2.80	2.80	2.63
Patronage exclusion	(23.80)	(23.80)	(37.63)
Asset retirement obligations	(11.33)	3.57	(0.16)
Deferred revenues and membership withdrawal	3.23	(28.78)	5.11
Operating liabilities, net of right-of-use assets (1)	11.29	—	—
Valuation Allowance	67.24	—	—
Other book tax differences	(2.43)	24.42	(2.82)
Regulatory treatment of deferred taxes	(68.68)	(0.46)	(3.91)
Effective tax rate	(0.68)%	(1.25)%	(1.78)%

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

We had a taxable loss of $46.4 million for 2019. At December 31, 2019, we have a federal net operating loss carryforward of $492.5 million of which pre-2018 tax years are subject to expiration periods between 2031 and 2037. We have $356.2 million of state net operating loss carryforwards subject to expiration periods between 2020 and 2037. We also have $0.3 million of alternative minimum tax credit carryforwards which is fully refundable through 2021. We established a valuation allowance of $30.5 million because it is more likely than not that some of the benefit from the federal and state net operating losses will not 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 2016 forward. We do not have any liabilities recorded for uncertain tax positions.

The Tax Cuts and Jobs Act ("TCJA"), enacted on December 22, 2017, reduced the corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. The Securities and Exchange Commission issued guidance in Staff Accounting Bulletin 118 ("SAB 118") which allows registrants to record provisional amounts for the accounting effects of TCJA during a measurement period not to extend beyond one year from the date of enactment. As of December 31, 2017, we recorded a $17.2 million provisional estimate to remeasure deferred tax balances at 21 percent.

NOTE 10 - REVENUE

Revenue from Contracts with Customers

Our revenues are derived primarily from the sale of electric power to our Members pursuant to long-term wholesale electric service contracts. Our contracts with our Members extend through 2050 for 42 Members and 2040 for the remaining Member.

Member electric sales

Revenues from electric power sales to our Members are primarily from our Class A rate schedule. Our Class A rate schedule for electric power sales to our 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 Members and are both measurements of the electric power provided to our Members. Therefore, the provision of electric power to our Members is one performance obligation. Prior to our 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 Member requires each incremental unit of electric power. We transfer control of the electric power to our Members over time and our 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 Members are invoiced based on the meter reading. Payments from our Members are received in accordance with the wholesale electric service contracts' terms, which is less than 30 days from the invoice date. Member electric sales revenue is recorded as Member electric sales on our consolidated statements of operations and Accounts receivable – Members on our consolidated statements of financial position.

In addition to our 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):

	2019	2018	2017
Non-member electric sales:			
Long-term contracts	$ 47,224	$ 45,314	$ 62,227
Short-term contracts	42,024	41,127	31,172
Recognition (deferral) of revenue, net	6,153	(51,678)	5,473
Coal Sales	6,662	1,075	40,697
Other	44,737	49,127	49,084
Total non-member electric sales and other operating revenue	$ 146,800	$ 84,965	$ 188,653

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 $6.2 million and $5.5 million of deferred non-member electric sales revenue for the years ended December 31, 2019 and December 31, 2017, 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 $7.4 million in 2019 and $7.9 million in 2018. Rent expense is included in operating expenses on our consolidated statements of operations. As of December 31, 2019, 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, **2019**
Operating leases	
Operating lease right-of-use assets	$ 8,376
Less: Accumulated amortization	(754)
Net operating lease right-of-use assets	$ 7,622
Operating lease liabilities – current	$ (5,533)
Operating lease liabilities – noncurrent	(1,846)
Total operating lease liabilities	$ (7,379)
Operating leases	
Weighted average remaining lease term (years)	9.5
Weighted average discount rate	3.80%

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

Year 1	$ 5,660
Year 2	517
Year 3	319
Year 4	275
Year 5	240
Thereafter	856
Total lease payments	$ 7,867
Less imputed interest	(488)
Total	$ 7,379

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 $12.1 million in 2019 and $17.6 million in 2018 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, and certain participants in the Yampa Project, own Trapper Mining. Organized as a cooperative, Trapper Mining supplied 24.7, 31.1 and 24.7 percent in 2019, 2018 and 2017, respectively, of the coal for the Yampa Project. Our 26.57 percent share of coal purchases from Trapper Mining was $18.6, $18.2 and $18.8 million in 2019, 2018 and 2017, respectively. Our membership interest in Trapper Mining of $15.9 and $15.4 million at December 31, 2019 and 2018, 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 1,467 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan ("RS Plan") except for the 225 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 53-0116145 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 2019, 2018 and 2017 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 $25.8, $27.8 and $26.7 million in 2019, 2018 and 2017, 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 280 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. As of December 31, 2019, the executive benefit restoration obligation included in accumulated postretirement benefit and postemployment obligations on our consolidated statements of financial position was $0.7 million.

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 280 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, $4.6 million, and $3.2 million in 2019, 2018, and 2017, 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, 2019, 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):

	2019	2018
Postretirement medical benefit obligation at beginning of period	$ 8,556	$ 8,455
Service cost	563	677
Interest cost	352	288
Benefit payments (net of contributions by participants)	(617)	(408)
Actuarial loss (gain)	1,341	(456)
Postretirement medical benefit obligation at end of period	$ 10,195	$ 8,556
Postemployment medical benefit obligation at end of period	375	371
Total postretirement and postemployment medical obligations at end of period	$ 10,570	$ 8,927

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):

	2019	2018
Amounts included in accumulated other comprehensive income at beginning of period	$ 375	$ (369)
Amortization of actuarial (gain) loss into income	(342)	367
Amortization of prior service cost into other income	(79)	(79)
Actuarial (loss) gain	(1,341)	456
Amounts included in accumulated other comprehensive income at end of period	$ (1,387)	$ 375

The assumptions used in the 2019 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	4.10 %
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)	12.35

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	$ 1,159	$ (992)
Net periodic postretirement medical benefit expense	138	(116)

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):

2020	$ 621
2021	719
2022	725
2023	685
2024	688
2025 through 2029	3,338
	$ 6,776

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, 2019	December 31, 2018
Net electric plant	$ 776,411	$ 794,549
Noncontrolling interest	111,717	110,169
Long-term debt	380,867	416,057
Accrued interest	11,050	12,056

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

	2019	2018	2017
Depreciation, amortization and depletion	$ 18,138	$ 18,138	$ 19,592
Interest	25,320	27,511	28,382

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 includes us. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in WFW. We also receive 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 have 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 are not the primary beneficiary of WFA and the entity is not consolidated. Our investment in WFA, accounted for using the cost method, was $2.4 million at December 31, 2019 and 2018 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 have 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. Our investment in WFW, accounted for using the cost method, was $0.1 million at December 31, 2019 and 2018 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 have a 26.57 percent cooperative member interest in Trapper Mining. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provide the financial support for the operation of the Trapper Mine. There is not sufficient equity at risk for Trapper Mining to finance its activities without additional financial support. Therefore, Trapper Mining is considered a variable interest entity in which we have 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) is shared with the cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of Trapper Mining and the entity is not consolidated. We record our investment in Trapper Mining using the equity method. Our membership interest in Trapper Mining was $15.9 million and $15.4 million at December 31, 2019 and 2018, respectively, and is included in investments in and advances to coal mines.

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. We also had a resource-contingent firm power sales contract with Public Service Company of Colorado totaling 100 megawatts. This contract expired in March 2017.

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under contracts that expire between 2020 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, 2019, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2020	$ 91,173
2021	64,637
2022	11,968
2023	7,816
2024	7,361
Thereafter	150,109
	$ 333,064

Our coal purchases were $125.4 million in 2019, $120.5 million in 2018, and $118.0 million in 2017.

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 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 pursuant to five 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, 2019, we have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,498 MWs, including 671 MWs of wind-based power purchase agreements and 800 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):

	2019	2018	2017
Basin	$ 145,008	$ 149,246	$ 152,977
WAPA	72,504	72,757	78,781
Other renewables	63,677	62,721	53,362

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. 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 or the effect it could have 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. The amount of our guarantees for reclamation obligations, or performance bonds, are based upon applicable state requirements and are different than the asset retirement obligations recognized on our consolidated financial statements in accordance with GAAP.

LEGAL: 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 current capacity of the transmission path, such utility's firm rights have been curtailed. The utility disputes its obligation to pay due to the current capacity of the transmission path and claims we, along with the other entity, are in breach of such transmission agreement. The utility notified us and the other entity of its intent to arbitrate in accordance with the agreement and claimed damages caused by the alleged breach of approximately $6.9 million, plus interest, attorney fees, and any future damages. The other entity filed a cross-claim against us claiming we are responsible for such entity's share of any damages. The matter was scheduled for arbitration to commence in January 2020. The arbitration was cancelled and the parties continue to discuss a resolution of this matter. It is not possible to predict whether this matter will be resolved without arbitration or whether we will incur any liability in connection with this matter.

At our July 2019 Board meeting, our Board authorized us to take action to place us under wholesale rate regulation by FERC. On July 23, 2019, we filed with FERC our initial tariff, including our stated rate cost of service filing, market based rate authorization, and transmission Open Access Transmission Tariff. Our FERC tariff filing included our current Class A rate schedule for electric power sales to our Members as the wholesale rates payable by our Members. On September 3, 2019, a membership agreement with a non-utility member, MIECO, Inc., became effective and we notified FERC of such and requested a partial waiver. The admission of the new member that was not an electric cooperative or governmental entity resulted in us no longer being exempt from FERC wholesale rate regulation pursuant to the Federal Power Act ("FPA"). On October 4, 2019, FERC issued an order rejecting our filings without prejudice to us submitting a more complete set of filings that cure the deficiencies set forth in such order. During the week of December 23, 2019, we filed our revised set of filings, including our stated rate cost of service filing, market based rate authorization, and transmission Open Access Transmission Tariff. The request was made to FERC to make the new tariffs retroactive to September 3, 2019. Numerous parties filed interventions or protests with FERC. Some of the interveners and protestors, including some of our Members and the Colorado Public Utilities Commission are alleging that we are not FERC jurisdictional and are still exempt from FERC wholesale rate regulation pursuant to the FPA. Until we made our reapplication in December 2019, we were a FERC-jurisdictional public utility making sales and providing services without satisfying the FPA's filing obligations and FERC's prior notice requirements. FERC may require us to refund to our customers certain amounts collected for the entire period that the rate was collected without FERC's authorization, including Member and non-member electric sales and wheeling revenue. FERC may also impose civil penalties for the time period between when we became a FERC-jurisdictional public utility and when we made our reapplication in December 2019. Furthermore, current practices including our use of regulatory assets are subject to FERC approval and subject to change as a result. We cannot predict the outcome of our tariff filings, but expect FERC to rule on our tariff filings by the end of March 2020. It is not possible to predict if FERC will require us to refund amounts to our customers, if FERC will impose civil penalties, if FERC will approve our current practices regarding use of regulatory assets, or to estimate any liability associated with this matter.

NOTE 16 – QUARTERLY FINANCIAL DATA (UNAUDITED)

Unaudited operating results by quarter for 2019 and 2018 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
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)(1)	45,309
2018					
Operating revenues	$ 318,508	$ 327,513	$ 398,157	$ 276,659	$ 1,320,837
Operating margins	40,299	41,716	81,393	(2,015)	161,393
Net margins attributable to the Association	8,094	4,378	46,398	(16,136)(2)	42,734

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

(2) In the fourth quarter of 2018, we deferred $51.7 million of non-member electric sales revenue.

NOTE 17 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 12, 2020, which is the date when the financial statements were issued.

On January 8, 2020, our Board approved the early retirements of Escalante Generating Station, Craig Generating Station Units 2 and 3 and the Colowyo Mine.

The 253-megawatt, coal-fired Escalante Generating Station, which is located near Prewitt, New Mexico, will be retired by the end of 2020. In connection with such early retirement, in the first quarter of 2020, in accordance with accounting requirements, we will recognize a one-time impairment loss of approximately $282 million. Our Board approved the deferral of the impairment loss to be recovered from our Members in rates through the end of 2045, which was the depreciable life of Escalante Generating Station; however, such deferral is subject to approval by FERC. In addition, we expect to incur decommission, employee related, and other expenses for Escalante Generating Station of approximately $26 million through 2022. The early retirement of the Escalante Generating Station is expected to impact approximately 107 employees.

The 410-megawatt Craig Generating Station Unit 2, which is part of a three-unit, coal-fired generating facility in Craig, Colorado, with a net book value of $82.5 million as of December 31, 2019, will be retired by 2030. The 448-megawatt Craig Generating Station Unit 3, with a net book value of $348.6 million as of December 31, 2019, will also be retired by 2030. The retirement date for Craig Generating Station Units 2 and 3 was previously estimated to be 2039 and 2044, respectively. The shortened life increases annual depreciation expense in the amount of approximately $6.6 million for Craig Generating Station Unit 2 and approximately $21.1 million for Craig Generating Station Unit 3; however, such recovery of increased expense through rates is subject to approval by FERC. In addition, we expect to incur decommissioning, employee related, and other expenses for Craig Generating Station Units 2 and 3 of approximately $40 million through 2032. The early retirement of the Craig Generating Station is expected to impact approximately 253 employees.

The Colowyo Mine produces coal used at Craig Generating Station and will cease coal production by 2030, at which time operations would turn entirely to reclamation. The Colowyo Mine has a net book value of $239 million as of December 31, 2019. The shortened life increases annual depreciation, amortization and depletion expense in the amount of approximately $12.7 million for the Colowyo Mine; however, such recovery of increased expense through rates is subject to approval by FERC. We are unable to determine other shutdown costs of the Colowyo Mine at this time. The early retirement of the Colowyo Coal Mine is expected to impact approximately 219 employees.

On March 10, 2020, our Board took action to unrestrict the entire balance of the restricted cash related to deferred revenue in response to volatile market conditions. See Note 2 – Cash, Cash Equivalents and Restricted Cash and Investments.

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, 2019 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, 2019. 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, 2019.

Changes in Internal Control over Financial Reporting

There were no changes that occurred during the fourth quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 43 Members. Each Member elects its representative to serve on our Board. Each of our directors must be a general manager, director or trustee of a 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 Members' business and brings insight to our Members' operations which we believe qualifies them to serve on our Board. The directors on our Board and their ages as of March 1, 2020 are as follows:

NAME	AGE	MEMBER-REPRESENTATIVE
Rick Gordon—Chairman and President	66	Mountain View Electric Association, Inc.
Scott Wolfe—Vice Chairman	56	San Luis Valley Rural Electric Cooperative, Inc.
Julie Kilty—Secretary	61	Wyrulec Company
Stuart Morgan—Treasurer	73	Wheat Belt Public Power District
Matt M. Brown—Assistant Secretary	68	High Plains Power, Inc.
Timothy Rabon—Assistant Secretary	59	Otero County Electric Cooperative, Inc.
Arthur W. Connell—Executive Committee	66	Central New Mexico Electric Cooperative, Inc.
Donald Keairns—Executive Committee	60	San Isabel Electric Association, Inc.
Douglas Shawn Turner—Executive Committee	58	The Midwest Electric Cooperative Corporation
Charles Abel	51	Sangre de Cristo Electric Association, Inc.
Leroy Anaya	63	Socorro Electric Cooperative, Inc.
Robert Baca	55	Mora-San Miguel Electric Cooperative, Inc.
Robert Bledsoe	70	K.C. Electric Association
Lawrence Brase	73	Southeast Colorado Power Association
Leo Brekel	68	Highline Electric Association
Jerry Burnett	73	High West Energy, Inc.
Richard Clifton	78	Carbon Power & Light, Inc.
Lucas Cordova Jr.	54	Jemez Mountains Electric Cooperative, Inc.
Mark Daily	67	Gunnison County Electric Association, Inc.
John "Jack" Finnerty	80	Wheatland Rural Electric Association
Gary Fuchser	65	Northwest Rural Public Power District
Joel Gilbert	61	Southwestern Electric Cooperative, Inc.
Ronald Hilkey	80	White River Electric Association, Inc.
Ralph Hilyard	81	Roosevelt Public Power District
Hal Keeler	91	Columbus Electric Cooperative, Inc.
Kyle S. Martinez	31	Delta-Montrose Electric Association
Brian McCormick	44	United Power, Inc.
Thaine Michie	79	Poudre Valley Rural Electric Association, Inc.
William Mollenkopf	70	Empire Electric Association, Inc.
Stanley Propp	73	Chimney Rock Public Power District
Steve M. Rendon	65	Northern Rio Arriba Electric Cooperative, Inc.
Claudio Romero	73	Continental Divide Electric Cooperative, Inc.
Peggy A. Ruble	66	Garland Light & Power Company
Donald Russell	72	Big Horn Rural Electric Company
Roger Schenk	56	Y-W Electric Association, Inc.
Brian Schlagel	70	Morgan County Rural Electric Association
Gary Shaw	65	Springer Electric Cooperative, Inc.
Jack Sibold	74	San Miguel Power Association, Inc.
Kirsten Skeehan	60	La Plata Electric Association, Inc.
Darryl Sullivan	69	Sierra Electric Cooperative, Inc.
Carl Trick II	72	Mountain Parks Electric, Inc.
William Wilson	65	Niobrara Electric Association, Inc.
Phillip Zochol	44	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. He also serves as a director of WFA and Trapper Mining. Mr. Gordon owns and operates Gordon Insurance, an independent insurance agency with offices in Calhan, Flagler, Limon and Sterling, Colorado.

Scott Wolfe has served on our Board since June 2008 and is Vice Chairman of the Board. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Wolfe serves as Secretary of San Luis Valley Rural Electric Cooperative, Inc. He is a farmer and owner of Lobo Farm LLC.

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.

Timothy Rabon has served on our Board since April 2014 and is Assistant Secretary 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.

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. Mr. Connell also serves as a director of Federated Rural Electric Insurance Exchange.

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 External Affairs-Member Relations Committee. Mr. Abel serves as Treasurer of Sangre de Cristo Electric Association. He is a commercial loan officer for High Country Bank in Salida and Buena Vista, Colorado. He is also a licensed CPA and owned a tax practice with offices in Buena Vista and Montrose, Colorado for the last 15 years.

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 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.

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 Engineering and Operations 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.

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.

Richard Clifton has served on our Board since June 2009. He is a member of the Finance and Audit Committee. Mr. Clifton serves as a director of Carbon Power & Light, Inc. Mr. Clifton is also President of the board of directors of Wyoming Rural Electric Association.

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. and is a former member service manager for Gunnison County Electric Association, Inc. He is on the Colorado Renewable Energy Society Policy Committee.

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.

Gary Fuchser has served on our Board since August 2013. He is a member of the Engineering and Operations Committee. Mr. Fuchser serves as a director of Northwest Rural Public Power District. He is a farmer in Gordon, Nebraska and the President of Fuchser Farms Inc.

Joel Gilbert has served on our Board since August 2018. He is a member of the External Affairs-Member Relations Committee. Mr. Gilbert serves as Vice President of Southwestern Electric Cooperative, Inc. He is a retired ranch manager.

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.

Kyle S. Martinez has served on our Board since July 2017. He is a member of the External Affairs-Member Relations Committee. Mr. Martinez serves as director of Delta-Montrose Electric Association. He is employed by Touch of Care, where he manages operations in multiple rural Colorado towns. Mr. Martinez also owns and operates a farm in Olathe, Colorado.

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.

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.

William Mollenkopf has served on our Board since June 2009. He is a member of the Finance and Audit Committee. Mr. Mollenkopf serves as a director of Empire Electric Association, Inc. He is a retired optometrist.

Stanley Propp has served on our Board since April 2015. He is a member of the Engineering and Operations Committee. He 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 External Affairs-Member Relations 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 self-employed in 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 a Vice President of Garland Light & Power. She is a retired executive assistant to the Park County Board of County Commissioners in Cody, Wyoming.

Donald Russell has served on our Board since March 2012. He is a member of the Finance and Audit Committee. Mr. Russell serves as President of Big Horn Rural Electric Company. He is a partner in the CPA Firm of Russell and Russell. He is also a partner in the farming operation of Russell Land & Livestock.

Roger Schenk has served on our Board since April 2019. He is a member of the External Affairs-Member Relations Committee. Mr. Schenk serves as Chairman of Y-W Electric Company. He is owner and operator of Schenk Family Farm.

Brian Schlagel has served on our Board since May 2005. He is a member of the Finance and Audit Committee. Mr. Schlagel serves as a director of Morgan County Rural Electric Association. He is a half owner of Schlagel Farms.

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.

Jack Sibold has served on our Board since June 2014. He is a member of the Engineering and Operations Committee. Mr. Sibold serves as a director of San Miguel Power Association, Inc. He is a director of Tri-County Water Conservancy District. As the former director of R&D for Coorstek, he has been engaged in ceramic engineering consulting.

Kirsten Skeehan has served on our Board since May 2018. She is a member of the External-Affairs-Member Relations Committee. Ms. Skeehan serves as a director of La Plata Electric Association, Inc. Ms. Skeehan is the Chief Financial Officer and Managing Member of Pagosa Baking Company LLC.

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.

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 the Assistant Secretary/Treasurer 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. Mr. Trick also serves as a director of Trapper Mining.

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. 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 Members. Such representative must be a general manager, director or trustee of a Member.

Executive Officers

The following table sets forth the names and positions of our executive officers and their ages as of March 1, 2020:

NAME	AGE	POSITION
Duane Highley	58	Chief Executive Officer
Joel Bladow	60	Senior Vice President, Transmission
Patrick L. Bridges	61	Senior Vice President/Chief Financial Officer
Ellen Connor	62	Senior Vice President, Organizational Services/Chief Technology Officer
Jennifer Goss	50	Senior Vice President, Member Relations
Barry Ingold	56	Senior Vice President, Generation
Bradford Nebergall	61	Senior Vice President, Energy Management
Kenneth V. Reif	68	Senior Vice President, General Counsel
Barbara Walz	57	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 37 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 38 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 37 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.

Ellen Connor is our Senior Vice President, Organizational Services/Chief Technology Officer and has served in that position since 2014. Ms. Connor previously served as Senior Manager, Financial Planning & Analysis and Insurance. Previous roles at Tri-State included Senior Manager, Enterprise Risk Management, and management of various finance functions. Prior to Tri-State's merger with Plains Electric Generation and Transmission Cooperative, Inc. in 2000, Ms. Connor served as Chief Financial Officer of Plains Electric Generation and Transmission Cooperative, Inc. Ms. Connor has a Bachelor of Science in business administration and is a Certified Treasury Professional. Ms. Connor has over 37 years of experience in the electric utility industry.

Jennifer Goss is our Senior Vice President, Member Relations and has served in that position since 2013. 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 21 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 22 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 33 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 40 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 23 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 non-bargaining employees. Effective January 25, 2019, there are no bargaining employees at the New Horizon Mine.

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.

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
Scott Wolfe
Julie Kilty
Stuart Morgan
Matt M. Brown
Timothy Rabon
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, Scott Wolfe, Julie Kilty, Stuart Morgan, Matt M. Brown, Timothy Rabon, 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. Wolfe is our Vice Chairman, Ms. Kilty is our Secretary, Mr. Morgan is our Treasurer, Mr. Brown is our Assistant Secretary and Mr. Rabon is our Assistant Secretary. All of the members of our Executive Committee are directors of our Members. Each of our Members has a wholesale electric service contract with us and we received revenue from each of our Members in excess of $120,000 in 2019.

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 2019). 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)	2019	$ 1,043,482	$ 877,155	$ 121,078	$ 2,041,715
Chief Executive Officer					
Micheal S. McInnes (3)	2019	$ 903,652	$ 238,140	$ 13,527	**(4)** 1,155,319
Chief Executive Officer	2018	859,848	295,276	44,248	1,199,372
	2017	790,072	216,476	37,344	1,043,892
Patrick L. Bridges	2019	445,209	105,878	50,194	601,281
Senior VP/CFO	2018	431,081	351,082	47,608	829,771
	2017	418,305	268,002	46,513	732,820
Ellen Connor	2019	305,151	229,397	31,843	566,391
Senior VP, Organizational	2018	291,640	499,139	30,228	821,007
Services/CTO	2017	278,894	425,965	29,629	734,488
Bradford Nebergall	2019	407,506	98,391	51,624	557,521
Senior VP, Energy	2018	394,951	267,508	45,622	708,081
Management	2017	383,244	209,686	44,587	637,517
Barry Ingold	2019	369,677	136,107	27,493	533,277
Senior VP, Generation	2018	358,494	304,013	23,790	686,297
	2017	347,869	234,329	21,813	604,011

(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 Chief Executive Officer on April 5, 2019 at which time Micheal McInnes became Special Advisor to the Association.
(3) Michael McInnes retired on June 30, 2019.
(4) Excludes any payments made under the RS Plan and NRECA Pension Restoration Plan. These payments are identified in the Defined Benefit Plan table below.

Retention Agreements

On June 27, 2018, we entered into 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, Organization Services/CTO. The retention agreements were made effective June 27, 2018 and end on June 1, 2020. In consideration of the above mentioned named executives continuing employment during this period, the executive is eligible to receive a retention payment on June 1, 2020 in the amount set forth 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, Organization Services/CTO	73,616

If prior to June 1, 2020, an above mentioned executive's employment is terminated by us for cause or by the executive for any reason, the entire retention payment for such executive is forfeited. If an above mentioned executive's employment is involuntarily terminated prior to June 1, 2020 by us, without cause, such termination shall result in an immediate vesting of the entire retention payment and the retention payment will be paid within thirty days of the executive's date of termination. The retention agreements are not employment agreements and do 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, 2019. As a result of changes in Internal Revenue Service regulations, the annual base salary used in determining benefits is limited to $280,000 effective January 1, 2019.

Name	Number of years Credited Service as of December 31, 2019	RS Plan Present Value of Accumulated Benefit as of December 31, 2019	Pension Restoration Plans Present Value of Accumulated Benefit as of December 31, 2019	Payments During 2019
Duane D. Highley (1)	9 months	$ 2,386,142	$ 688,079	None
Micheal S. McInnes	4 years (2)	364,035	2,136,943	$ 2,500,978
Patrick L. Bridges	12 years, 3 months	1,033,147	552,879	None
Ellen Connor	37 years, 10 months	2,844,300	135,186	None
Bradford Nebergall	11 years, 3 months	947,673	385,203	None
Barry Ingold	15 years, 0 months	1,002,819	246,161	None

(1) Mr. Highley began employment with us on April 1, 2019. He has 9 months of service with us and a total of 35 years and 6 months in the RS Plan due to prior years of participation at previous employers. His participation in the NRECA Executive Benefit Restoration plan started new on April 1, 2019.

(2) Mr. McInnes retired on June 30, 2019 and was paid out his NRECA Pension Restoration benefit in the amount of $2,136,943 directly from us, and was paid out his RS Plan benefit from NRECA

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, 2019.

Chief Executive Officer Pay Ratio

The 2019 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		2019 Total Compensation (1)
Median annual total compensation of all employees (excluding Chief Executive Officer)	$	109,515
Annual Total Compensation of Duane D. Highley, Chief Executive Officer		2,556,336
Ratio of the median annual total compensation of all employees to the annual total compensation of Duane D. Highley, Chief Executive Officer		1.0:23.3

(1) Includes change in pension value from 2018 to 2019.

(2) Since Duane Highley began employment with us on April 1, 2019, the Annual Total Compensation shown in this table for the purpose of determining the compensation ratio is his annualized salary plus the change in pension value and other compensation as shown in the compensation table previously.

In determining the median employee, a listing was prepared of all active employees of us and our subsidiaries as of December 31, 2019. 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 2019. We determined the compensation of our median employee by (1) utilizing the W-2 Box 5 wages for all active employees for 2019 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 full or partial day is $625. The Chairman and President is also reimbursed for all out-of-pocket expenses incurred on our behalf.

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 meetings.

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, including tax. 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 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.

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 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 2019 for services rendered. Director fees are paid after submission of receipts by the Members to us. Amounts in the table reflect actual payments made in 2019. Directors are also reimbursed for expenses as described above.

Name	**2019 Board Fees(1)**
Charles Abel	$ 15,000
Leroy Anaya	29,000
Robert Baca	26,500
Robert Bledsoe	32,500
Lawrence Brase	20,500
Leo Brekel	10,500
Matt M. Brown	26,500
Jerry Burnett	21,000
Richard Clifton	26,000
Arthur W. Connell	25,750
Lucas Cordova Jr.	28,000
Mark Daily	16,500
John "Jack" Finnerty	74,000
Gary Fuchser	14,500
Joel Gilbert	23,500
Rick Gordon(2)	167,876
Jack Hammond(3)	13,500
Ronald Hilkey	18,500
Ralph Hilyard	14,500
Donald L. Kaufmann(3)	500
Donald Keairns	31,500
Hal Keeler	31,500
Julie Kilty	29,000
Kyle S. Martinez	22,000
Thaine Michie	21,000
William Mollenkopf	24,500
Stuart Morgan	33,000
Richard Newman(3)	11,500
Stanley Propp	19,500
Timothy Rabon	26,750
Steve Rendon	27,000
Claudio Romero	20,500
Donald Russell	24,500
Roger Schenk	19,000
Brian Schlagel	24,500
Donald Schutz(3)	8,000
Gary Shaw	10,500
Jack Sibold	17,000
Kirsten Skeehan	19,500
Charles Soehner (3)	42,630
Darryl Sullivan	24,700
Carl Trick II	18,500
William Wilson	4,500
Scott Wolfe	46,000
Phillip Zochol	11,500

(1) Various directors have deferred a total of $85,800 of the actual Board fee payments made in 2019. Some directors deferred up to 100 percent of their fee payments. Some directors submitted reports for services rendered for prior years.

(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, 2019.

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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 Member that it represents on our Board. Each of our Members has a wholesale electric service contract with us and we received revenue from each of our Members in excess of $120,000 in 2019.

Jeff Wadsworth is the President and Chief Executive Officer of PVREA and served as director on our Board in July and August 2019. PVREA is our Member and our revenue from PVREA under our wholesale electric service contract with PVREA was $100.1 million, or 8.1 percent, of our Member revenue and 7.2 percent of our total operating revenue in 2019.

In 2019, certain of our directors served on the board of directors of other entities in which we have ownership interests, including Trapper Mining. We purchased coal for the Yampa Project from Trapper Mining of $18.6 million in 2019.

Other than as described above, in 2019, 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, with the exception of Jeff Wadsworth who served as director in July and August 2019, satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet all the requirements set forth in our Bylaws. Mr. Wadsworth does not qualify as an independent director because he is the President and Chief Executive Officer of Poudre Valley Rural Electric Association, Inc., an organization from which we received more than 5 percent of our gross revenues for the fiscal year ended December 31, 2019. 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.

	2019	2018
Audit Fees(1)	$ 813,000	$ 706,000
Audit-Related Fees(2)	—	20,000
Tax Fees(3)	55,000	35,000
All Other Fees(4)	—	—
Total	$ 868,000	$ 761,000

(1) Audit of annual financing statements and review of interim financial statements included in SEC filings and services rendered in connection with financings, including comfort letters, consents, and comment letters.
(2) Other audit-related services primarily related to accounting consultation pertaining to accounting standards impacting future periods.
(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 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 2019 and 2018, 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. (Filed as Exhibit 3.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc. (Filed as Exhibit 3.1 to the Registrant's Form 8-K filed on April 8, 2019, File No. 333-212006.)
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.)
4.2†	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*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.13.2*	Secured Promissory note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to Loan C-0047-9077
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-0047-9078

4.15* 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.

4.16.1* Notes, dated April 8, 2009, from Tri-State to various purchasers, relating to Series 2009C Note Purchase Agreement

4.16.2* Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement

4.16.3* Notes, dated December 12, 2017, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement

4.16.4* Notes, dated April 12, 2018, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement

4.17* 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

4.18.1* Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of $400,000,000

4.18.2* 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 November 1, 2001, between Tri-State and Delta-Montrose Electric Association (Filed as Exhibit 10.3 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.5† 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.)

10.6†	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.)
10.7.1†	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.)
10.7.2†	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.)
10.8†	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.)
10.9†	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.)
10.10†	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.)
10.11†	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.)
10.12**†	Director Elective Deferred Fees Plan, effective January 1, 2005, executed December 11, 2008 (Filed as Exhibit 10.10 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.13**†	Executive Benefit Restoration Plan, dated December 12, 2014 (Filed as Exhibit 10.18 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.14**†	Amended and Restated Pension Restoration Plan of Tri-State Generation and Transmission Association, Inc., dated December 12, 2014 (Filed as Exhibit 10.19 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.15**†	Retention Agreement for Patrick L. Bridges, effective as of June 27, 2018, between Tri State and Patrick L. Bridges (Filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2018, File No. 333-203560.)
10.16**†	Retention Agreement for Bradford C. Nebergall, effective as of June 27, 2018, between Tri-State and Bradford C. Nebergall (Filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2018, File No. 333-203560.)
10.17**†	Retention Agreement for Barry W. Ingold, effective as of June 27, 2018, between Tri-State and Barry W. Ingold (Filed as Exhibit 10.3 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2018, File No. 333-203560.)
10.18**†	Retention Agreement for Ellen Connor, effective as of June 27, 2018, between Tri-State and Ellen Connor (Filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2018, File No. 333-203560.)
10.19**†	Form of Retention Agreement, effective as of June 27, 2018, between Tri-State and its other executive officers (other than Chief Executive Officer) (Filed as Exhibit 10.5 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2018, 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.

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* 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 12, 2020

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 12, 2020
/s/ PATRICK L. BRIDGES Patrick L. Bridges	Senior Vice President/Chief Financial Officer (principal financial officer)	March 12, 2020
/s/ DENNIS J. HRUBY Dennis J. Hruby	Senior Manager Controller (principal accounting officer)	March 12, 2020
/s/ RICK GORDON Rick Gordon	Chairman, President and Director	March 12, 2020
/s/ SCOTT WOLFE Scott Wolfe	Director	March 12, 2020
/s/ JULIE KILTY Julie Kilty	Director	March 12, 2020
/s/ STUART MORGAN Stuart Morgan	Director	March 12, 2020
/s/ MATT M. BROWN Matt M. Brown	Director	March 12, 2020
/s/ TIMOTHY RABON Timothy Rabon	Director	March 12, 2020
/s/ ARTHUR W. CONNELL Arthur W. Connell	Director	March 12, 2020

/s/ DONALD KEAIRNS Donald Keairns	Director	March 12, 2020
/s/ CHARLES ABEL Charles Abel	Director	March 12, 2020
/s/ LEROY ANAYA Leroy Anaya	Director	March 12, 2020
/s/ ROBERT BACA Robert Baca	Director	March 12, 2020
/s/ ROBERT BLEDSOE Robert Bledsoe	Director	March 12, 2020
/s/ LAWRENCE BRASE Lawrence Brase	Director	March 12, 2020
/s/ LEO BREKEL Leo Brekel	Director	March 12, 2020
Jerry Burnett	Director	
/s/ RICHARD CLIFTON Richard Clifton	Director	March 12, 2020
/s/ LUCAS CORDOVA, JR. Lucas Cordova, Jr.	Director	March 12, 2020
/s/ MARK DAILY Mark Daily	Director	March 12, 2020
/s/ JOHN FINNERTY John Finnerty	Director	March 12, 2020
/s/ GARY FUCHSER Gary Fuchser	Director	March 12, 2020
/s/ JOEL GILBERT Joel Gilbert	Director	March 12, 2020
/s/ RONALD HILKEY Ronald Hilkey	Director	March 12, 2020

/s/ RALPH HILYARD Ralph Hilyard	Director	March 12, 2020
/s/ HAL KEELER Hal Keeler	Director	March 12, 2020
/s/ KYLE S. MARTINEZ Kyle S. Martinez	Director	March 12, 2020
/s/ BRIAN MCCORMICK Brian McCormick	Director	March 12, 2020
/s/ THAINE MICHIE Thaine Michie	Director	March 12, 2020
/s/ WILLIAM MOLLENKOPF William Mollenkopf	Director	March 12, 2020
/s/ STANLEY PROPP Stanley Propp	Director	March 12, 2020
/s/ STEVE M. RENDON Steve M. Rendon	Director	March 12, 2020
/s/ CLAUDIO ROMERO Claudio Romero	Director	March 12, 2020
/s/ PEGGY A. RUBLE Peggy A. Ruble	Director	March 12, 2020
/s/ DONALD RUSSEL Donald Russell	Director	March 12, 2020
/s/ ROGER SCHENK Roger Schenk	Director	March 12, 2020
/s/ BRIAN SCHLAGEL Brian Schlagel	Director	March 12, 2020
/s/ GARY SHAW Gary Shaw	Director	March 12, 2020
Jack Sibold	Director	

/s/ KIRSTEN SKEEHAN Kirsten Skeehan	Director	March 12, 2020
/s/ DARRYL SULLIVAN Darryl Sullivan	Director	March 12, 2020
/s/ CARL TRICK II Carl Trick II	Director	March 12, 2020
/s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	March 12, 2020
/s/ WILLIAM WILSON William Wilson	Director	March 12, 2020
/s/ PHILLIP ZOCHOL Phillip Zochol	Director	March 12, 2020

Appendix A

Calculation of Financial Ratios

Equity to Capitalization Ratio

Indenture ECR	**2019** ($ in thousands)
Total Debt	$ 3,017,039
Total Margins & Equities	1,029,792
Total Capitalization	**$ 4,046,831**
Indenture ECR	**25.45%**

Debt Service Ratio

	Year Ended December 31, 2019 ($ in thousands)
Net Margins Available for Debt Service	
Net Margins	$ 45,309
Interest Expense	131,532
Amortization of debt discount or premium	2,608
Depreciation, depletion, obsolescence, amortization of property rights, etc.	136,462
Lease Expenses	71,227
Net Margins Available for Debt Service (NMADS)	$ 387,138
Annual Debt Service Requirements	
Principal of all debt of the Association	$ 62,310
Less: Committed Take Out	(9,000)
Interest on all debt coming due	132,983
Amortization of Balloon Payments	60,067
Lease Payments	81,733
Annual Debt Service Requirement (ADSR)	$ 328,093
Debt Service Ratio	**1.18**

(1) 2019 financial ratios are calculated using GAAP financials. In future years, FERC financials will be used to calculate financial ratios.