

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

**For the quarterly period ended March 31, 2021
OR**

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

For the transition period from to

Commission File No. 333-212006

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

(Exact name of registrant as specified in its charter)

Colorado

(State or other jurisdiction of incorporation or organization)

1100 West 116th Avenue

Westminster, Colorado

(Address of principal executive offices)

84-0464189

(I.R.S. employer identification number)

80234

(Zip Code)

(303) 452-6111

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. **Yes** **No** (Note: The registrant is not subject to the filing requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), but voluntarily files reports with the Securities and Exchange Commission. 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 the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. **Large accelerated filer** **Accelerated filer**

Non-accelerated filer **Smaller reporting company** **Emerging growth company**

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
None	None	None

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. **The registrant is a membership corporation and has no authorized or outstanding equity securities.**

**TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
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FOR THE QUARTER ENDED MARCH 31, 2021**

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GLOSSARY

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

Abbreviations or Acronyms	Definition
Basin	Basin Electric Power Cooperative
Board	Board of Directors
CDPHE	Colorado Department of Public Health and Environment
CFC	National Rural Utilities Cooperative Finance Corporation
CoBank	CoBank, ACB
Colowyo Coal	Colowyo Coal Company L.P., a subsidiary of ours
COPUC	Colorado Public Utilities Commission
COVID-19	coronavirus disease 2019 that was declared a pandemic by the World Health Organization in March 2020
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
DSR	Debt Service Ratio (as defined in our Master Indenture)
ECR	Equity to Capitalization Ratio (as defined in our Master Indenture)
DMEA	Delta-Montrose Electric Association
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
Jurisdictional PDO	our Petition for Declaratory Order on Jurisdiction under Part II of Federal Power Act, filed with FERC on December 23, 2019, EL20-16-000
kWh	kilowatt hour
LIBOR	London Interbank Offered Rate
LPEA	La Plata Electric Association, Inc.
Master Indenture	Master First Mortgage Indenture, Deed of Trust and Security Agreement, dated effective as of December 15, 1999, between us and Wells Fargo Bank, National Association, as trustee
MBPP	Missouri Basin Power Project
Members	our Utility Members and Non-Utility Members
Moody's	Moody's Investors Services, Inc.
MW	megawatt
MWh	megawatt hour
Non-Utility Members	our non-utility members
Revolving Credit Agreement	Credit Agreement, dated as of April 25, 2018, between us and CFC, as administrative agent
S&P	Standard & Poor's Global Ratings
SEC	Securities and Exchange Commission
Springerville Partnership	Springerville Unit 3 Partnership LP, a subsidiary of ours
Springerville Unit 3	Springerville Generating Station Unit 3
Tri-State, We, Our, Us, the Association	Tri-State Generation and Transmission Association, Inc.
United Power	United Power, Inc.
Utility Members	our electric distribution member systems, consisting of both Class A members and Class B members

FORWARD-LOOKING STATEMENTS

This quarterly report on Form 10-Q contains “forward-looking statements.” All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as the timing of various regulatory and other actions, future capital expenditures, business strategy and development, construction, operation, or closure of facilities (often, but not always, identified through the use of words or phrases such as “will likely result,” “are expected to,” “will continue,” “is anticipated,” “estimated,” “forecast,” “projection,” “target” and “outlook”) are forward-looking statements.

Although we believe that in making these forward-looking statements our expectations are based on reasonable assumptions, any forward-looking statement involves uncertainties and there are important factors that could cause actual results to differ materially from those expressed or implied by these forward-looking statements.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Tri-State Generation and Transmission Association, Inc.

Consolidated Statements of Financial Position

(dollars in thousands)

	March 31, 2021	December 31, 2020
	(unaudited)	
ASSETS		
Property, plant and equipment		
Electric plant		
In service	\$ 6,338,525	\$ 6,254,652
Construction work in progress	85,386	89,447
Total electric plant	6,423,911	6,344,099
Less allowances for depreciation and amortization	(3,073,651)	(2,991,393)
Net electric plant	3,350,260	3,352,706
Other plant	457,837	456,924
Less allowances for depreciation, amortization and depletion	(145,304)	(133,012)
Net other plant	312,533	323,912
Total property, plant and equipment	3,662,793	3,676,618
Other assets and investments		
Investments in other associations	164,248	162,975
Investments in and advances to coal mines	2,614	2,799
Restricted cash and investments	4,546	4,682
Other noncurrent assets	15,390	14,889
Total other assets and investments	186,798	185,345
Current assets		
Cash and cash equivalents	109,483	127,187
Restricted cash and investments	274	205
Deposits and advances	37,604	32,012
Accounts receivable—Utility Members	88,369	96,637
Other accounts receivable	16,286	20,570
Electric plant held for sale	—	4,877
Coal inventory	53,211	55,762
Materials and supplies	81,567	82,119
Total current assets	386,794	419,369
Deferred charges		
Regulatory assets	699,480	710,268
Prepayment—NRECA Retirement Security Plan	20,146	21,490
Other	46,638	33,646
Total deferred charges	766,264	765,404
Total assets	\$ 5,002,649	\$ 5,046,736
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	\$ 969,029	\$ 978,519
Accumulated other comprehensive loss	(6,357)	(5,714)
Noncontrolling interest	113,807	114,851
Total equity	1,076,479	1,087,656
Long-term debt	3,147,423	3,200,181
Total capitalization	4,223,902	4,287,837
Current liabilities		
Utility Member advances	18,128	16,592
Accounts payable	107,590	98,654
Accrued expenses	31,583	40,736
Current asset retirement obligations	11,080	11,044
Accrued interest	45,321	27,520
Accrued property taxes	27,503	32,794
Current maturities of long-term debt	94,592	87,587
Total current liabilities	335,797	314,927
Deferred credits and other liabilities		
Regulatory liabilities	203,981	224,953
Deferred income tax liability	19,702	19,591
Asset retirement and environmental reclamation obligations	127,705	127,045
Other	72,401	54,600
Total deferred credits and other liabilities	423,789	426,189
Accumulated postretirement benefit and postemployment obligations	19,161	17,783
Total equity and liabilities	\$ 5,002,649	\$ 5,046,736

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

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

	Three Months Ended March 31,	
	2021	2020
Operating revenues		
Utility Member electric sales	\$ 272,798	\$ 292,763
Non-member electric sales	38,174	15,813
Other	15,000	10,890
	<u>325,972</u>	<u>319,466</u>
Operating expenses		
Purchased power	87,017	71,015
Fuel	60,547	61,069
Production	40,901	43,188
Transmission	44,671	41,540
General and administrative	14,587	16,215
Depreciation, amortization and depletion	52,755	47,024
Coal mining	1,541	2,734
Other	2,551	7,683
	<u>304,570</u>	<u>290,468</u>
Operating margins	21,402	28,998
Other income		
Interest	877	1,305
Capital credits from cooperatives	4,273	3,353
Other income (expense)	857	(250)
	<u>6,007</u>	<u>4,408</u>
Interest expense		
Interest	36,115	38,867
Interest charged during construction	(974)	(1,961)
	<u>35,141</u>	<u>36,906</u>
Income tax expense (benefit)	109	(209)
Net margins including noncontrolling interest	<u>(7,841)</u>	<u>(3,291)</u>
Net margin attributable to noncontrolling interest	(1,649)	(1,319)
Net margins attributable to the Association	<u>\$ (9,490)</u>	<u>\$ (4,610)</u>

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

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

	Three Months Ended March 31,	
	<u>2021</u>	<u>2020</u>
Net margins including noncontrolling interest	\$ (7,841)	\$ (3,291)
Other comprehensive loss:		
Unrealized loss on securities available for sale	(34)	—
Amortization of actuarial loss on postretirement benefit obligation included in net margin	512	933
Unrecognized prior service cost	<u>(1,121)</u>	<u>(7,373)</u>
Other comprehensive loss	(643)	(6,440)
Comprehensive loss including noncontrolling interest	(8,484)	(9,731)
Net comprehensive income attributable to noncontrolling interest	(1,649)	(1,319)
Comprehensive loss attributable to the Association	<u>\$ (10,133)</u>	<u>\$ (11,050)</u>

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

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

	Three Months Ended March 31,	
	2021	2020
Patronage capital equity at beginning of period	\$ 978,519	\$ 1,031,063
Net margins attributable to the Association	(9,490)	(4,610)
Patronage capital equity at end of period	969,029	1,026,453
Accumulated other comprehensive loss at beginning of period	(5,714)	(1,518)
Unrealized loss on securities available for sale	(34)	—
Amortization of prior service cost	512	933
Unrecognized prior service cost	(1,121)	(7,373)
Accumulated other comprehensive loss at end of period	(6,357)	(7,958)
Noncontrolling interest at beginning of period	114,851	111,717
Net comprehensive income attributable to noncontrolling interest	1,649	1,319
Equity distribution to noncontrolling interest	(2,693)	(1,268)
Noncontrolling interest at end of period	113,807	111,768
Total equity at end of period	\$ 1,076,479	\$ 1,130,263

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

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

	Three Months Ended March 31,	
	2021	2020
Operating activities		
Net margins including noncontrolling interest	\$ (7,841)	\$ (3,291)
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	52,755	47,024
Amortization of NRECA Retirement Security Plan prepayment	1,343	1,343
Amortization of debt issuance costs	627	602
Impairment loss	—	259,761
Deferred impairment loss and other closure costs	—	(268,163)
Recognition of deferred revenue	(20,834)	—
Deposits associated with generator interconnection requests	17,130	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,159)	(693)
Changes in operating assets and liabilities:		
Accounts receivable	10,224	14,230
Coal inventory	2,550	1,843
Materials and supplies	552	954
Accounts payable and accrued expenses	15,585	8,039
Accrued interest	17,800	17,321
Accrued property taxes	(5,291)	(2,063)
Other	(7,430)	(11,353)
Net cash provided by operating activities	76,011	65,554
Investing activities		
Purchases of plant	(22,775)	(36,171)
Changes in deferred charges	(9,786)	(6,094)
Proceeds from other investments	72	68
Net cash used in investing activities	(32,489)	(42,197)
Financing activities		
Changes in Member advances	1,536	(6,905)
Payments of long-term debt	(46,109)	(41,994)
Proceeds from issuance of long-term debt	—	200,000
Decrease in short-term borrowings, net	—	(87,600)
Retirement of patronage capital	(13,705)	(13,326)
Equity distribution to noncontrolling interest	(2,693)	(1,268)
Other	(322)	(195)
Net cash provided by (used in) financing activities	(61,293)	48,712
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	(17,771)	72,069
Cash, cash equivalents and restricted cash and investments – beginning	132,074	113,768
Cash, cash equivalents and restricted cash and investments – ending	\$ 114,303	\$ 185,837
Supplemental cash flow information:		
Cash paid for interest	\$ 18,074	\$ 21,222
Cash paid for income taxes	\$ —	\$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	\$ (616)	\$ 1,044

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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements
For the Three Months Ended March 31, 2021 and 2020

NOTE 1 – PRESENTATION OF FINANCIAL INFORMATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) for interim financial information and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. These unaudited consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2020 filed with the SEC. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. Our consolidated financial position as of March 31, 2021, results of operations for the three months ended March 31, 2021 and 2020, and cash flows for the three months ended March 31, 2021 and 2020 are not necessarily indicative of the results that may be expected for an entire year or any other period.

Basis of Consolidation

We are a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis serving large portions of Colorado, Nebraska, New Mexico and Wyoming. We were incorporated under the laws of the State of Colorado in 1952. We have three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and non-utility members. We have forty-two electric distribution member systems who are Class A members to which we provide electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members. We have three non-utility members (“Non-Utility Members”). Our Class A members and any Class B members are collectively referred to as our “Utility Members.” Our Class A members, any Class B members, and Non-Utility Members are collectively referred to as our “Members.” The addition of Non-Utility Members in 2019 and specifically the addition of MIECO, Inc. on September 3, 2019 removed the exemption from the Federal Energy Regulatory Commission’s (“FERC”) regulation for us, thus subjecting us to full rate and transmission jurisdiction by FERC effective September 3, 2019. Our stated rate to our Class A members was filed at FERC on December 23, 2019 and was accepted by FERC on March 20, 2020. On April 30, 2021, we filed a proposed settlement agreement with FERC related to our stated rate to our Class A members. See Note 17 – Legal.

We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with GAAP, the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

The accompanying financial statements reflect the consolidated accounts of Tri-State Generation and Transmission Association, Inc. (“Tri-State”, “we”, “our”, “us” or “the Association”), our wholly-owned and majority-owned subsidiaries, and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 16 – Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities. We have eliminated all significant intercompany balances and transactions in consolidation.

Jointly Owned Facilities

We own undivided interests in two jointly owned generation 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 other operating expenses is included in our consolidated financial statements.

Our share in each jointly owned facility is as follows as of March 31, 2021 (dollars in thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Generating Station Units 1 and 2	24.00 %	\$ 395,810	\$ 253,638	\$ 418
MBPP - Laramie River Station	27.13 %	498,918	317,538	4,051
Total		<u>\$ 894,728</u>	<u>\$ 571,176</u>	<u>\$ 4,469</u>

NOTE 2 – ACCOUNTING FOR RATE REGULATION

In accordance with the accounting requirements related to regulated operations, some revenues and expenses have been deferred at the discretion of our Board of Directors (“Board”), subject to FERC approval, if based on regulatory orders or other available evidence, it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs that we expect to recover from our Utility Members based on rates approved by the applicable authority. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Utility Members based on rates approved by the applicable authority. Expected recovery of deferred costs and returning deferred credits are based on specific ratemaking decisions by FERC or precedent for each item. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expense concurrent with their recovery through rates.

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

	March 31, 2021	December 31, 2020
Regulatory assets		
Deferred income tax expense (1)	\$ 19,641	\$ 19,641
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	80,851	81,424
Goodwill – J.M. Shafer (3)	45,584	46,296
Goodwill – Colowyo Coal (4)	35,903	36,161
Deferred debt prepayment transaction costs (5)	130,145	132,302
Deferred Holcomb expansion impairment loss (6)	87,651	88,819
Unrecovered plant (7)	299,705	305,625
Total regulatory assets	<u>699,480</u>	<u>710,268</u>
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	3,155	3,293
Deferred revenues (9)	42,883	63,717
Membership withdrawal (10)	157,943	157,943
Total regulatory liabilities	<u>203,981</u>	<u>224,953</u>
Net regulatory asset	<u>\$ 495,499</u>	<u>\$ 485,315</u>

- (1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.
- (2) Represents deferral of the loss on acquisition related to the Springerville Generating Station Unit 3 (“Springerville Unit 3”) prepaid lease expense upon acquiring a controlling interest in the Springerville Unit 3 Partnership LP (“Springerville Partnership”) in 2009. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of \$2.3 million annually through the 47-year period ending in 2056 and recovered from our Utility Members through rates.
- (3) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of \$2.8 million annually through the 25-year period ending in 2036 and recovered from our Utility Members through rates.

- (4) Represents goodwill related to our acquisition of Colowyo Coal Company LP (“Colowyo Coal”) in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of \$1.0 million annually through the 44-year period ending in 2056 and recovered from our Utility Members through rates.
- (5) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of \$8.6 million annually over the 21.4-year period ending in 2036 and recovered from our Utility Members through rates.
- (6) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights for the expansion of the Holcomb Generating Station. The regulatory asset for the deferred impairment loss is being amortized to depreciation, amortization and depletion expense in the amount of \$4.7 million annually over the 20-year period ending in 2039 and recovered from our Utility Members through rates.
- (7) Represents deferral of the impairment losses related to the early retirement of the Nucla and Escalante Generating Stations. The deferred impairment loss for Nucla Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of \$11.3 million annually over the 3.3-year period ending in December 2022 and recovered from our Utility Members through rates. The deferred impairment loss for Escalante Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of \$11.3 million annually over the 25-year period ending in December 2045, which was the depreciable life of Escalante Generating Station, and is expected to be recovered from our Utility Members through rates. The annual amortization is expected to approximate the former annual Escalante Generating Station depreciation for the remaining life of the asset.
- (8) Represents deferral of a realized gain of \$4.6 million related to the October 2017 settlement of a forward starting interest rate swap. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A and refunded to Utility Members through reduced rates when recognized in future periods.
- (9) Represents deferral of the recognition of non-member electric sales revenues. These deferred non-member electric sales revenues will be refunded to Utility Members as part of our rate stabilization measures when recognized in non-member electric sales revenue in future periods.
- (10) Represents the deferral of the recognition of other income related to the withdrawal of former Utility Members from membership in us. The total deferred membership withdrawal income will be refunded to Utility Members as part of our rate stabilization measures when recognized in other income in future periods.

NOTE 3 – 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):

	March 31, 2021	December 31, 2020
Basin Electric Power Cooperative	\$ 118,295	\$ 118,295
National Rural Utilities Cooperative Finance Corporation - patronage capital	11,933	11,933
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,149	15,221
CoBank, ACB	12,707	11,141
Western Fuels Association, Inc.	2,200	2,283
Other	3,964	4,102
Investments in other associations	<u>\$ 164,248</u>	<u>\$ 162,975</u>

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during the three months ended March 31, 2021 or during 2020.

NOTE 4 – 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.

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Restricted cash and investments represent funds designated by our Board for specific uses and funds restricted by contract or other legal reasons. A portion of the funds are amounts that have been restricted by contract that are expected to be settled within one year. These funds are therefore classified as current on our consolidated statements of financial position. The other funds are for amounts restricted by contract or other legal reasons that are expected to be settled beyond one year. These funds are classified as noncurrent and are included in other assets and investments on our consolidated statements of financial position.

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

	March 31, 2021	December 31, 2020
Cash and cash equivalents	\$ 109,483	\$ 127,187
Restricted cash and investments - current	274	205
Restricted cash and investments - noncurrent	4,546	4,682
Cash, cash equivalents and restricted cash and investments	<u>\$ 114,303</u>	<u>\$ 132,074</u>

NOTE 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

Accounts Receivable

We record accounts receivable for our unconditional rights to consideration arising from our performance under contracts with our Members and other parties. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible. See Note 12 – Revenue.

Contract liabilities (unearned revenue)

A contract liability represents an entity’s obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. During the three months ended March 31, 2021, we recognized \$0.1 million of this unearned revenue in other operating revenues on our consolidated statements of operations.

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

	March 31, 2021	December 31, 2020
Accounts receivable - Utility Members	<u>\$ 88,369</u>	<u>\$ 96,637</u>
Other accounts receivable - trade:		
Non-member electric sales	3,239	5,231
Other	9,855	9,785
Total other accounts receivable - trade	13,094	15,016
Other accounts receivable - nontrade	3,192	5,554
Total other accounts receivable	<u>\$ 16,286</u>	<u>\$ 20,570</u>
Contract liabilities (unearned revenue)	<u>\$ 6,301</u>	<u>\$ 6,025</u>

NOTE 6 – OTHER DEFERRED CHARGES

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

	March 31, 2021	December 31, 2020
Preliminary surveys and investigations	\$ 12,142	\$ 12,886
Advances to operating agents of jointly owned facilities	11,425	2,071
Operating lease right-of-use assets	7,999	7,985
Other	15,072	10,704
Total other deferred charges	\$ 46,638	\$ 33,646

We make expenditures for preliminary surveys and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects. If construction results, the preliminary survey and investigation expenditures will be reclassified to electric plant - construction work in progress. If the work is abandoned, the related preliminary survey and investigation expenditures will be charged to the appropriate operating expense account or the expense could be deferred as a regulatory asset to be recovered from our Utility Members through rates subject to approval by our Board and FERC.

We make advance payments to the operating agents of jointly owned facilities to fund our share of costs expected to be incurred under each project including MBPP – Laramie River Station, and Yampa Project – Craig Generating Station Units 1 and 2. We also make advance payments to the operating agent of Springerville Unit 3.

A right-of-use asset represents a lessee’s right to control the use of the underlying asset for the lease term. Right-of-use assets are included in other deferred charges and presented net of accumulated amortization. See Note 14 – Leases.

NOTE 7 – 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 amount of \$17.7 million as of March 31, 2021. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a debt service ratio requirement on an annual basis and an equity to capitalization ratio requirement of at least 18 percent at the end of each fiscal year. Other than the Springerville certificates that has a debt service ratio requirement of at least 1.02 on an annual basis, all other long-term debt contains a debt service ratio requirement of at least 1.10 on an annual basis.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation (“CFC”), as lead arranger and administrative agent, in the amount of \$650 million (“Revolving Credit Agreement”) that expires on April 25, 2023 and 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. As of March 31, 2021, we had \$650.0 million in availability under the Revolving Credit Agreement.

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

	March 31, 2021	December 31, 2020
Total debt	\$ 3,262,606	\$ 3,308,715
Less debt issuance costs	(24,963)	(25,590)
Less debt discounts	(9,595)	(9,659)
Plus debt premiums	13,967	14,302
Total debt adjusted for debt issuance costs, discounts and premiums	3,242,015	3,287,768
Less current maturities	(94,592)	(87,587)
Long-term debt	\$ 3,147,423	\$ 3,200,181

NOTE 8 – 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. As of March 31, 2021 and December 31, 2020, we had no commercial paper outstanding.

At March 31, 2021, \$500.0 million of the commercial paper back-up sublimit remained available under the Revolving Credit Agreement. See Note 7 – Long-Term Debt.

NOTE 9 – 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.

Coal mines: We have asset retirement obligations for the final reclamation costs and environmental obligations for post-reclamation monitoring related to the Colowyo Mine and the New Horizon Mine. The New Horizon Mine is currently in post-reclamation monitoring. One pit at the Colowyo Mine began final reclamation in 2019 with the other remaining pits still being actively mined.

Generation: We have asset retirement obligations related to equipment, dams, ponds, wells and underground storage tanks at the generating stations.

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

	Three Months Ended March 31, 2021
Obligations at beginning of period	\$ 138,089
Liabilities incurred	—
Liabilities settled	(107)
Accretion expense	803
Change in cash flow estimate	—
Total obligations at end of period	\$ 138,785
Less current obligations at end of period	(11,080)
Long-term obligations at end of period	\$ 127,705

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

NOTE 10 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES

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

	March 31, 2021	December 31, 2020
Transmission easements	\$ 19,621	\$ 19,983
Operating lease liabilities - noncurrent	1,761	1,590
Contract liabilities (unearned revenue) - noncurrent	3,611	3,702
Customer deposits	8,935	7,712
Financial liabilities - reclamation	11,924	12,081
Deposits associated with generator interconnection requests	17,130	—
Other	9,419	9,532
Total other deferred credits and other liabilities	<u>\$ 72,401</u>	<u>\$ 54,600</u>

In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. \$29.4 million will be paid by us for these easements from 2021 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were \$19.6 and \$20.0 million as of March 31, 2021 and December 31, 2020, respectively, which are recorded as other deferred credits and other liabilities.

A lease liability represents a lessee’s obligation to make lease payments over the lease term. The long-term portion of our lease liabilities are included in other deferred credits and other liabilities and the current portion of our lease liabilities are included in current liabilities. See Note 14 – Leases.

A contract liability represents an entity’s obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in contract liabilities (unearned revenue) until recognized in other operating revenues over the life of the agreement. We have received deposits from various parties and those that may still be required to be returned are a liability and these are reflected in customer deposits.

NOTE 11 – EMPLOYEE BENEFIT PLANS

Postretirement Benefits Other Than Pensions

We sponsor three medical plans for all non-bargaining unit employees under the age of 65. Two of the plans provide postretirement medical benefits to full-time non-bargaining unit employees and retirees who receive benefits under those plans, who have attained age 55, and who elect to participate. All three of these non-bargaining unit medical plans offer postemployment medical benefits to employees on long-term disability. The plans were unfunded at March 31, 2021, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles. As of June 30, 2021, the plans will cease to provide postretirement medical benefits for employees who retire after June 30, 2021.

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):

	Three Months Ended March 31, 2021
Postretirement medical benefit obligation at beginning of period	\$ 9,985
Service cost	150
Interest cost	65
Benefit payments (net of contributions by participants)	(148)
Postretirement medical benefit obligation at end of period	\$ 10,052
Postemployment medical benefit obligation at end of period	419
Total postretirement and postemployment medical obligations at end of period	<u>\$ 10,471</u>

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 income on our consolidated statements of financial position. If the unrecognized amount is in excess of 10 percent of the projected benefit obligation, amounts are reclassified out of accumulated other comprehensive income and included in net income as the excess is amortized over the average remaining service lives of the active plan participants. Unrecognized actuarial gains and losses have been determined per actuarial studies for the postretirement medical benefit obligation.

The net unrecognized actuarial gains and losses related to the postretirement medical benefit obligations are included in accumulated other comprehensive income as follows (dollars in thousands):

	Three Months Ended March 31, 2021
Accumulated other comprehensive loss at beginning of period	\$ (841)
Amortization of prior service credit into other income	(20)
Accumulated other comprehensive loss at end of period	<u>\$ (861)</u>

Defined Benefit Plans

We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan, both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees 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 April 30, 2021, the plans will cease to add new participants and no new executives will be eligible for the plan.

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The NRECA Executive Benefit Restoration Plan obligations are determined annually (during the first quarter of the subsequent year) by an NRECA actuary and are included in accumulated postretirement benefit and postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	Three Months Ended March 31, 2021
Executive benefit restoration obligation at beginning of period	\$ 7,379
Service cost	137
Interest cost	53
Actuarial loss	1,121
Executive benefit restoration at end of period	<u>\$ 8,690</u>
Fair value of plan assets at beginning of period	\$ 6,955
Employer contributions	403
Actual return on plan assets	\$ (41)
Fair value of plan assets at end of period	<u>\$ 7,317</u>
Net liability recognized	<u>\$ 1,373</u>

The service cost component of our net periodic benefit cost is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations. In December 2020, we established an irrevocable trust with an independent third party to fund the NRECA Executive Benefit Restoration Plan. The trust is funded quarterly to the prior year obligation as determined by the NRECA actuary.

In accordance with the accounting standard related to defined benefit pension plans, actuarial gains and losses are not recognized in income but are instead recorded in accumulated other income on our consolidated statements of financial position. If the unrecognized amount is in excess of 10 percent of the projected benefit obligation, amounts are reclassified out of accumulated other comprehensive income and included in net income as the excess is amortized over the average remaining service lives of the active plan participants. Unrecognized actuarial gains and losses have been determined per actuarial studies for the executive benefit restoration obligation.

The net unrecognized actuarial gains and losses related to the executive benefit restoration obligations are included in accumulated other comprehensive income as follows (dollars in thousands):

	Three Months Ended March 31, 2021
Accumulated other comprehensive loss at beginning of period	\$ (4,873)
Amortization of prior service cost into other income	220
Amortization of actuarial loss	171
Curtailment and settlement	141
Unrecognized actuarial loss	(1,121)
Accumulated other comprehensive loss at end of period	<u>\$ (5,462)</u>

NOTE 12 – REVENUE

Revenue from Contracts with Customers

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

Member electric sales

Revenues from electric power sales to our Utility Members are primarily from our Class A rate schedule filed with FERC. Our Class A rate schedule for electric power sales to our Utility Members consist of three billing components: an energy rate and two demand rates. Our Class A rate schedule is variable and is approved by our Board and FERC. Energy and demand have the same pattern of transfer to our Utility Members and are both measurements of the electric power provided to our Utility Members. Therefore, the provision of electric power to our Utility Members is one performance obligation. Prior to our Utility Members' requirement for electric power, we do not have a contractual right to consideration as we are not obligated to provide electric power until the Utility Member requires each incremental unit of electric power. We transfer control of the electric power to our Utility Members over time and our Utility Members simultaneously receive and consume the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method, meter readings are taken at the end of each month for billing purposes, energy and demand are determined after the meter readings and Utility Members are invoiced based on the meter reading. Payments from our Utility Members are received in accordance with the wholesale electric service contracts' terms, which is less than 30 days from the invoice date. Utility Member electric sales revenue is recorded as Utility Member electric sales on our consolidated statements of operations and Accounts receivable – Utility Members on our consolidated statements of financial position.

In addition to our Utility Member electric sales, we have non-member electric sales and other operating revenue which consist of several revenue streams. The following revenue is reflected on our consolidated statements of operations as follows (dollars in thousands):

	Three Months Ended March 31,	
	2021	2020
Non-member electric sales:		
Long-term contracts	\$ 8,706	\$ 12,144
Short-term contracts	8,634	3,669
Recognition of deferred revenue	20,834	—
Other	15,000	10,890
Total non-member electric sales and other operating revenue	<u>\$ 53,174</u>	<u>\$ 26,703</u>

Non-member electric sales

Revenues from electric power sales to non-members are primarily from long-term contracts and short-term market sales.

Prior to our customers' demand for energy, we do not have a contractual right to consideration as we are not obligated to provide energy until the customer demands each incremental unit of energy. We transfer control of the energy to our customer over time and our customer simultaneously receives and consumes the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method. Payments are received in accordance with the contract terms, which is less than 30 days after the invoice is received by the customer.

Other operating revenue

Other operating revenue consists primarily of wheeling, transmission, water and coal sales revenue . Other operating revenue also includes revenue we receive from two of our Non-Utility Members. Wheeling revenue is earned when we charge other energy companies for transmitting electricity over our transmission lines (payments are received in accordance with the contract terms which is within 20 days of the date the invoice is received). Transmission revenue is from Southwest Power Pool's scheduling of transmission across our transmission assets in the Eastern Interconnection because of our membership in it (Southwest Power Pool collects the revenue from the customer and pays us for the scheduling, system control, dispatch transmission service, and the annual transmission revenue requirement). Water revenue is derived from supplying water resources 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 from the invoice date). Each of these services or goods are provided over time and progress toward completion of our performance obligations are measured using the output method. Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. We have an obligation to deliver coal and progress of completion toward our performance obligation is measured using the output method. Our performance obligation is completed as coal is delivered.

NOTE 13 – INCOME TAXES

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes, which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. Effective January 1, 2020, we adopted the normalization method of recognizing deferred income taxes pursuant to FERC regulation. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit). Our subsidiaries are not subject to FERC regulation and continue to use a flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Our consolidated statements of operations included an income tax expense of \$0.1 million for the three months ended March 31, 2021 and an income tax benefit of \$0.2 million for the comparable period in 2020.

NOTE 14 – LEASES

Leasing Arrangements As Lessee

We determine if an arrangement is a lease upon commencement of the contract. If an arrangement is determined to be a long-term lease (greater than 12 months), we recognize a right-of-use asset and lease liability based on the present value of the future minimum lease payments over the lease term at the commencement date. As most of our leases do not provide an implicit rate, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. Our lease terms may also include options to extend or terminate the lease when it is reasonably certain that we will exercise those options. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term. Right-of-use assets are included in other deferred charges, the current portion of lease liabilities is included in 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.

We have elected to apply the short-term lease exception for contracts that have a lease term of twelve months or less and do not include an option to purchase the underlying asset. Therefore, we do not recognize a right-of-use asset or lease liability for such contracts. We recognize short-term lease payments as expense on a straight-line basis over the lease term. Variable lease payments that do not depend on an index or rate are recognized as expense.

We have lease agreements as lessee for the right to use various facilities and operational assets. Rent expense for all short-term and long-term operating leases was \$1.0 million for the three months ended March 31, 2021 and \$0.9 million for the comparable period in 2020. Rent expense is included in operating expenses on our consolidated statements of operations. As of March 31, 2021, there were no arrangements accounted for as finance leases.

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

	March 31, 2021	December 31, 2020
Operating leases		
Operating lease right-of-use assets	\$ 9,331	\$ 9,223
Less: Accumulated amortization	(1,332)	(1,238)
Net operating lease right-of-use assets	<u>\$ 7,999</u>	<u>\$ 7,985</u>
Operating lease liabilities - current	\$ (499)	\$ (526)
Operating lease liabilities - noncurrent	(1,761)	(1,590)
Total operating lease liabilities	<u>\$ (2,260)</u>	<u>\$ (2,116)</u>
Operating leases		
Weighted average remaining lease term (years)	7.7	7.6
Weighted average discount rate	3.85 %	3.84 %

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

Year 1	\$	527
Year 2		365
Year 3		336
Year 4		286
Year 5		100
Thereafter		690
Total lease payments	\$	2,304
Less imputed interest		(44)
Total	\$	2,260

Leasing Arrangements As Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of \$1.8 million and \$1.6 million for the three months ended March 31, 2021 and 2020, respectively, 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 16- 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.

NOTE 15 – FAIR VALUE

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal or in the most advantageous market when no principal market exists. The fair value measurement accounting guidance emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability (market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress). In considering market participant assumptions in fair value measurements, a three-tier fair value hierarchy for measuring fair value was established which prioritizes the inputs used in measuring fair value as follows:

Level 1 inputs are based upon quoted prices for identical instruments traded in active (exchange-traded) markets. Valuations are obtained from readily available pricing sources for market transactions (observable market data) involving identical assets or liabilities.

Level 2 inputs are based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active and model-based valuation techniques (such as option pricing models, discounted cash flow models) for which all significant assumptions are observable in the market.

Level 3 inputs consist of unobservable market data which is typically based on an entity's own assumptions of what a market participant would use in pricing an asset or liability as there is little, if any, related market activity.

In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. The assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability.

Executive Benefit Restoration Plan Trust

In December 2020, we established an irrevocable trust with an independent third party to fund the NRECA Executive Benefit Restoration Plan. The trust is funded quarterly to the prior year obligation as determined by the NRECA actuary. The trust consists of investments in equity and debt securities and are measured at fair value on a recurring basis. Changes in the fair value of investments in equity securities are recognized in earnings and changes in fair value of investments in debt securities classified as available-for-sale are recognized in other comprehensive income until realized. The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our

consolidated statements of financial position. The cost and fair values of our marketable securities are as follows (dollars in thousands):

	March 31, 2021		December 31, 2020	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
EBR Trust investments	\$ 7,384	\$ 7,316	\$ 6,955	\$ 6,955

Marketable Securities

We hold marketable securities in connection with the directors’ and executives’ elective deferred compensation plans which consist of investments in stock funds, bond funds and money market funds. These securities are measured at fair value on a recurring basis with changes in fair value recognized in earnings. The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our consolidated statements of financial position. The cost and fair values of our marketable securities are as follows (dollars in thousands):

	March 31, 2021		December 31, 2020	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	\$ 493	\$ 503	\$ 491	\$ 478

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was \$88.2 million as of March 31, 2021 and \$94.6 million as of December 31, 2020.

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):

	March 31, 2021		December 31, 2020	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	\$ 3,262,606	\$ 3,748,334	\$ 3,308,715	\$ 3,908,497

NOTE 16 – 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):

	March 31, 2021	December 31, 2020
Net electric plant	\$ 753,739	\$ 758,273
Noncontrolling interest	113,807	114,852
Long-term debt	301,066	342,355
Accrued interest	3,488	9,942

Our consolidated statements of operations include the following Springerville Partnership expenses for the three months ended March 31, 2021 and 2020 (dollars in thousands):

	March 31,	
	2021	2020
Depreciation, amortization and depletion	\$ 4,534	\$ 4,534
Interest	5,185	5,861

The revenue associated with the Springerville Partnership lease has been eliminated in consolidation. Income, losses and cash flows of the Springerville Partnership are allocated to the general and limited partners based on their equity ownership percentages. The net income or loss attributable to the 49 percent noncontrolling equity interest in the Springerville Partnership is reflected on our consolidated statements of operations.

NOTE 17 – LEGAL

Other than as disclosed below, we do not expect any litigation or proceeding pending or threatened against us to have a potential material effect on our financial condition, results of operations or cash flows.

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

On March 20, 2020, FERC issued orders regarding our Jurisdictional PDO and our tariff filings. FERC's orders generally accepted our tariff filings and recognized that we became FERC jurisdictional on September 3, 2019, but did not make the tariffs retroactive to September 3, 2019. However, FERC specifically provided that no refunds are due on our Utility Member rates and our transmission service rates prior to March 26, 2020. FERC did not impose any civil penalties on us. FERC also did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered 206 proceedings to determine the justness and reasonableness of our rates and wholesale electric service contracts. FERC also rejected our Board Policy 115 ("BP 115") and member project contracts related to our Utility Members' election to provide up to 5 percent of their electric power requirements pursuant to their wholesale electric service contracts on the grounds that the initial filing was incomplete without Board Policy 101 ("BP 101") related to the self-supply in excess of the 5 percent annual allowance. The tariff rates were referred to an administrative law judges to encourage settlement of material issues and to hold a hearings if settlements is not reached. Any refunds to the applicable tariff rates would only apply for sales after March 26, 2020. The settlement proceedings for both our Utility Member rates and our transmission service rates are continuing. On April 30,

2021, we filed a proposed settlement agreement related to our Utility Member stated rate, including BP 115, BP 101, and Board Policy 119 (“BP 119”), with FERC for approval, as further discussed below. FERC’s March 20, 2020 order regarding our Jurisdictional PDO denied our requested declaration regarding the preemption of the United Power and LPEA proceeding at the COPUC stating the proceeding was not currently preempted.

On April 13, 2020, we filed a request for rehearing limited to the issue of preemption of the United Power and LPEA proceeding at the COPUC related to the contract termination payment amount as described in our Jurisdictional PDO. Requests for rehearing related to both the Jurisdictional PDO and tariff filings were filed with FERC by other parties, including United Power. On August 28, 2020, FERC issued an order (“August 28 Order”) on rehearing related to our Jurisdictional PDO which modified its March 20, 2020 decision by finding exclusive jurisdiction over our contract termination payments and preempting the jurisdiction of the COPUC as of September 3, 2019. The August 28 Order also set aside requests for rehearing filed with FERC by other parties related to the Jurisdictional PDO. Requests for rehearing related to FERC’s August 28 Order were filed with FERC by United Power and LPEA. On October 28, 2020, FERC issued an order denying the requests for rehearing filed by United Power and LPEA.

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

On October 19, 2020, we filed our BP 119 related to our community solar program that provides for our Utility Members to develop community solar projects up to specified annual output limits separate from and in addition to the 5 percent self-supply provision of the wholesale electric service contracts and our first community solar contract with a Utility Member with FERC for acceptance. On December 18, 2020, FERC accepted BP 119 and the community solar contract, to be effective December 19, 2020, subject to refund. FERC referred it to FERC’s hearing and settlement judge procedures, which were consolidated with the ongoing settlement and hearing procedures in effect for our member rates docket.

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

On April 30, 2021, we filed a proposed settlement agreement related to our Utility Member stated rate, including our wholesale electric service contracts, BP 115, BP 101, and BP 119, with FERC for approval. With the exception of four reserved issues contingent on United Power being a settling party, the proposed settlement resolves all issues set for hearing and settlement procedures related to our Utility Member rates. The proposed settlement provides for us to implement a two-stage, graduated reduction in the charges making up our Class A rate schedule of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from current rates) thereafter until the date a new Class A wholesale rate schedule is approved by FERC and goes into effect. The proposed settlement rates will remain in effect at least through May 31, 2023 and during such time period, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule. We have also agreed to file a new Class A rate schedule after May 31, 2023 and prior to September 1, 2023. During the moratorium, we will establish a rate design committee to oversee the development of the new rate. Three of the reserved issues are related to the transmission component of our rates and the fourth relates to our community solar program. Additionally, with the exception of one reserved issue regarding transmission demand charges applicable to certain electric storage resources, each of the reserved issues will have prospective effect only, with the intent that any FERC rulings would be implemented in future rate filings. This proposed settlement agreement is subject to FERC’s approval. We also filed a motion with FERC’s Chief Judge seeking immediate implementation, effective as of March 1, 2021, of the two percent rate reduction, pending FERC’s approval of the proposed settlement. On May 5, 2021, the Chief Judge issued an order granting implementation of the

proposed settlement rates effective as of March 1, 2021 pending FERC's consideration of the proposed settlement agreement. In connection with the proposed settlement anticipated to become effected as of March 1, 2021, our Utility Member electric sales revenue and results of operations does not include approximately \$1.7 million of revenue associated with the two percent rate reduction for March 2021. Such amount is being held in reserve.

It is not possible to predict if FERC will require us to refund amounts to our customers for sales after March 26, 2020 on outstanding issues, if FERC will approve our current practices regarding use of regulatory assets are just and reasonable, if FERC will accept our proposed settlement agreement filed on April 30, 2021, if settlements will be reached without a hearing on outstanding issues, or to estimate any liability associated with these matters. In addition, we cannot predict the outcome of the 206 proceedings or any petitions for review filed with the D.C. Circuit Court of Appeals.

LPEA and United Power COPUC Complaints. Pursuant to our Bylaws, a Utility Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Utility Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. On November 5, 2019, LPEA filed a formal complaint with the COPUC alleging that we hindered LPEA's ability to seek withdrawal from us. On November 6, 2019, United Power filed a formal complaint with the COPUC, alleging that we hindered United Power's ability to explore its power supply options by either withdrawing from us or continuing as a Utility Member under a partial requirements contract. On November 20, 2019, the COPUC consolidated the two proceeding into one, 19F-0621E.

A hearing was held on May 18-20, 2020. On July 10, 2020, the administrative law judge issued a recommended decision, but the COPUC on its own motion stayed the recommended decision. On September 18, 2020, LPEA and United Power filed a Joint Motion to Lodge FERC's August 28 Order, and asserting additional corporate law arguments related to the legality of our addition of Non-Utility Members. We filed a response on September 29, 2020. On October 22, 2020, the COPUC determined that COPUC's jurisdiction over United Power and LPEA's complaints was preempted by FERC, the COPUC does not have jurisdiction over corporate law matters, and dismissed both complaints without prejudice. On November 25, 2020, LPEA and United Power jointly filed an application for rehearing, reargument, and reconsideration with the COPUC of its October 22, 2020 decision. The COPUC denied LPEA's and United Power's November 25 application, which denial became final on December 28, 2020. On January 27, 2021, United Power filed a Writ for Certiorari or Judicial Review, an appeal, in the Denver County District Court, 2021CV30325, of the COPUC's decision to dismiss United Power's complaint. On February 17, 2021, the Denver County District Court granted our unopposed motion to intervene as a defendant in United Power's appeal of the COPUC's dismissal. On April 30, 2021, United Power filed its opening brief of petitioner. It is not possible to predict the outcome in this matter.

United Power's Adams District Court Complaints: On May 4, 2020, United Power filed a Complaint for Declaratory Judgement and Damages in the Adams County District Court, 2020CV30649, against us and our three Non-Utility Members alleging, among other things, that the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void, the April 2020 Board approvals related to a "Make-Whole" methodology for a contract termination payment and buy-down payment formula are also void, that we have breached the wholesale electric service contract with United Power, and that we and our three Non-Utility Members conspired to deprive the COPUC of jurisdiction over the contract termination payment of our Colorado Utility Members. On June 20, 2020, we filed our answer denying United Power's allegations and request for relief, and asked the court to dismiss United Power's claims. We asserted counterclaims against United Power, and are seeking relief from United Power's breach of our Bylaws and declaratory judgement that the April 2019 Bylaws amendment and the April 2020 Board approvals related to a "Make-Whole" methodology for a contract termination payment and buy-down payment formula are valid. On June 20, 2020, the three Non-Utility Members filed a joint motion to dismiss. United Power filed its response on July 30, 2020. On December 10, 2020, the Non-Utility Members motion to dismiss was granted. On December 23, 2020, United Power sought to amend its May 2020 complaint to add LPEA as an additional plaintiff and to add the claims from its November 2020 complaint, discussed below, into its amended complaint and to dismiss the November 2020 complaint against us. The court has not yet decided whether United Power will be granted leave to file its amended complaint.

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

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

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

We are owned entirely by our forty-five members. We have three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and non-utility members. For our forty-two Class A members, we provide electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members, and therefore all our Utility Members are currently Class A members. We have three Non-Utility Members. Thirty-eight of our Utility Members are not-for-profit, electric distribution cooperative associations. Four Utility Members are public power districts, which are political subdivisions of the State of Nebraska. We became regulated as a public utility under Part II of the FPA on September 3, 2019 when we admitted a Non-Utility Member, MIECO, Inc. (a non-governmental/non-electric cooperative entity), as a new Member/owner.

We supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long term purchase contracts and short term energy purchases. We own, lease, have undivided percentage interests in, have tolling arrangements or long-term purchase contracts with respect to, various generating facilities. Our diverse generation portfolio provides us with maximum available power of 4,174 MWs, of which approximately 1,166 MWs comes from renewables. In April 2021, the 104 MW Crossing Trails Wind Farm achieved commercial operation and we began purchasing energy pursuant to a fifteen year power purchase agreement. In 2020, we estimate that nearly a third of the energy delivered by us and our Utility Members to our Utility Members' customers came from non-carbon emitting resources.

We sold 4.0 million MWhs for the three months ended March 31, 2021, of which 93.7 percent was to Utility Members. Total revenue from electric sales was \$311.0 million for the three months ended March 31, 2021 of which 87.7 percent was from Utility Member sales. Our results for the three months ended March 31, 2021 were primarily impacted by seasonal weather changes, including record cold winter weather, as well as reduced sales due to disruptions of operations from our Utility Members' commercial customers associated with the COVID-19 pandemic.

- Utility Member electric sales decreased \$20.0 million, or 6.8 percent, primarily due to reduced membership and pandemic related issues as many commercial operations continued to be closed or severely reduced.
- Non-member electric sales increased \$22.4 million, or 141.4 percent, primarily due to rate stabilization measures. In order to better align with our financial goals, we have begun to recognize deferred revenue on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2021.
- Purchased power expense increased \$16.0 million, or 22.5 percent, primarily due to decreased generation from our generating resources because of favorable market conditions for purchasing power.
- Depreciation, amortization and depletion expense increased \$5.7 million, or 12.2 percent, primarily due to revisions to asset retirement obligations related to the South Taylor pit at the Colowyo Mine during the prior year.

Our Bylaws and Wholesale Electric Service Contracts

Our Bylaws require each Utility Member, unless otherwise specified in a written agreement or the terms of the Bylaws, to purchase from us electric power and energy as provided in the Utility Member's contract with us. This contract is the wholesale electric service contract with each Utility Member, which is an all-requirements contract. Each wholesale electric service contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive, at least 95 percent of its electric power requirements from us. Our wholesale electric service contracts with our 42 Utility Members extend through 2050. Each Utility Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Utility Member. As of March 31, 2021, 20 Utility Members have enrolled in this program with capacity totaling approximately 138 MWs of which 126 MWs are in operation.

Pursuant to our wholesale electric service contracts with our Utility Members, we convened a contract committee in 2019 and 2020, consisting of a representative from each Utility Member, to review the wholesale electric service contracts and to discuss alternative contracts for our Utility Members, including partial requirements contracts. Upon recommendations from the

contract committee, our Board approved a community solar program, a partial requirements structure, including a buy-down payment methodology, and a “Make-Whole” methodology for a contract termination payment. Each of these items recommended by the contract committee representing our Utility Members were filed with FERC for approval in 2020. FERC accepted each of these items, subject to refund, and referred them to FERC’s hearing and settlement judge procedures. For further information see “Item 1 – BUSINESS – MEMBERS – Contract Committee” in our annual report on Form 10-K for the year ended December 31, 2020.

Pursuant to our Bylaws, a Utility Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe; provided, however, that no Utility Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. In April 2020, the Board approved a “Make-Whole” methodology for a contract termination payment designed to leave remaining Utility Members in the same economic position after a Utility Member terminates its wholesale electric service contract as the remaining Utility Members would have had the Utility Member not terminated. Any termination of a Utility Member wholesale electric service contract shall continue to require Board approval. In April 2020, we filed with FERC the Board approved contract termination payment methodology. In June 2020, FERC accepted our contract termination payment methodology and referred it to FERC’s hearing and settlement judge procedures. In late 2020, certain Utility Members formally requested a contract termination payment amount for planning purposes, but have not provided a notice of intent to withdraw. In January 2021, we notified each of these Utility Members that the contract termination payment calculation is time-intensive and complex and that we are working on a contract termination procedure to be filed with FERC. In late February 2021, seven of our Utility Members filed a complaint with FERC seeking the contract termination payment amount on an expedited basis. In March 2021, we filed a motion to dismiss and answer. In March 2021, our Board approved a contract termination procedures Board policy that that was filed with FERC for approval. Fourteen interventions of our Utility Members have been filed with FERC related to such Board policy, including three Utility Members filing comments in support and eight Utility Members filing a protest or comments against such Board policy.

In May 2020, United Power filed a complaint for declaratory judgement and damages against us alleging, among other things, that the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void and that we have breached the wholesale electric service contract with United Power. In November 2020, United Power filed a complaint for declaratory relief against us seeking for the court to declare that our addition of the Non-Utility Members violated Colorado law. In December 2020, United Power sought to amend its May 2020 complaint to add LPEA as an additional plaintiff and to add the claims from its November 2020 complaint into its amended complaint and to dismiss the November 2020 complaint against us. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

Responsible Energy Plan

In January 2020, we announced our Responsible Energy Plan, which will advance our clean energy transition. Some of the highlights of the Responsible Energy Plan include:

- Eliminating all emissions from our coal-fired generating facilities in Colorado and New Mexico by 2030.
- By 2024, 50 percent of the electricity our Utility Members use is expected to come from clean energy.
- More local renewables for Utility Members through contract flexibility.
- Promoting participation in a regional transmission organization.
- Expanding electric vehicle infrastructure and beneficial electrification.

As part of our Responsible Energy Plan, in January 2020, we announced the early retirements of Craig Station by 2030 and Escalante Station by the end of 2020. In connection with such early retirements, our Board continues to evaluate the creation of additional regulatory assets and use of regulatory liabilities to ensure our Utility Member rates remain stable, if not lower, during this transition. A creation of regulatory assets to defer expenses associated with these early retirements or the utilization of regulatory liabilities would require FERC approval.

For further information regarding our Responsible Energy Plan, see “Item 1 – BUSINESS — MEMBERS – Responsible Energy Plan” in our annual report on Form 10-K for the year ended December 31, 2020.

COVID-19 Impacts

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

The economic impacts of the COVID-19 pandemic and the various government measures related to COVID-19 have caused a significant slowdown in certain sectors of the economy, including oil and gas, and a corresponding increase in unemployment. We have experienced changes in the load patterns of our Utility Members and decreased sales to our Utility Members and Utility Member revenue due to disruptions of operations from our Utility Members' commercial customers. We continue to monitor the impacts of COVID-19. The extent to which the COVID-19 pandemic may continue to impact our results of operations, including the long-term nature of the impacts, depends on numerous evolving factors, which are highly uncertain and difficult to predict, including the adoption rate of the COVID-19 vaccines, the scope and the timing to further contain the virus or treat its impact, and to what extent normal economic and operating conditions can resume, among others. We currently believe that we have sufficient liquidity to meet our anticipated capital and operating requirements. It is possible that actual, perceived or projected negative impacts to our business or Utility Members' businesses from the impacts of COVID-19 could be the impetus for negative rating action by credit rating agencies.

Critical Accounting Policies

The preparation of our financial statements in conformity with GAAP requires that our management make estimates and assumptions that affect the amounts reported in our consolidated financial statements. We base these estimates and assumptions on information available as of the date of the financial statements and they are not necessarily indicative of the results to be expected for the year. As of March 31, 2021, there were no material changes in our critical accounting policies as disclosed in our annual report on Form 10-K for the year ended December 31, 2020.

Factors Affecting Results

Master Indenture

As of March 31, 2021, we had approximately \$3.0 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Our Master Indenture requires us to establish rates annually that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis and permits us to incur additional secured obligations as long as after giving effect to the additional secured obligation, we will continue to meet the DSR requirement on both a historical and pro forma basis. Our Master Indenture also requires us to maintain an ECR of at least 18 percent at the end of each fiscal year. As of December 31, 2020, our DSR was 1.19 and our ECR was 24.7 percent. Pursuant to our Master Indenture, DSR and ECR are calculated based on unconsolidated Tri-State financials and calculated in accordance with the system of accounts proscribed by FERC, not GAAP.

Margins and Patronage Capital

We operate on a cooperative basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to meet certain financial requirements and to establish reasonable reserves. Revenues in excess of current period costs in any year are designated as net margins in our consolidated statements of operations. Net margins are treated as advances of capital by our Members and are allocated to our Utility Members on the basis of revenue from electricity purchases from us and to our Non-Utility Members as provided in their respective membership agreement.

Our Board Policy for Financial Goals and Capital Credits, approved and subject to change by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Utility Members. On a periodic basis, our Board will determine whether to retire any patronage capital, and in what amounts, to our Members. To date, we have retired approximately \$493.2 million of patronage capital to our Members.

Pursuant to our Board Policy for Financial Goals and Capital Credits, we set rates to achieve a DSR and ECR in excess of the requirements under our Master Indenture in order to mitigate the risk of potential negative variances between budgeted margins and actual margins. This policy establishes a goal of our Board to either defer revenues and incomes as a regulatory liability or recognize previously deferred revenues and incomes (as available) in an amount that will result in a DSR equal to a DSR goal for the applicable year as set forth in the policy. As allowed by our Bylaws, the deferral or recognition of previously deferred revenues and income is for the purpose of stabilizing margins and limiting rate increases from year to year. In order to better align with our financial goals, we have begun to recognize deferred revenue on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2021.

Rates and Regulation

On September 3, 2019, we became FERC jurisdictional for our Utility Member rates, transmission service, and our market based rates. In December 2019, we filed with FERC our tariff filings, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. In March 2020, FERC issued orders generally accepting our tariff filings, subject to refund for sales after March 26, 2020. FERC did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered 206 proceedings to determine the justness and reasonableness of our rates, including our Class A wholesale rate schedule (A-40) referenced below, and wholesale electric service contracts. The tariff rates were referred to an administrative law judge to encourage settlement of material issues and to hold a hearing if settlement is not reached. The settlement proceedings are continuing. On April 30, 2021, we filed a proposed settlement agreement related to our Utility Member stated rate with FERC for approval that provides for us to implement a two-stage, graduated reduction in the charges making up our A-40 rate of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from current rates) thereafter until the date a new Class A wholesale rate schedule goes into effect. This proposed settlement agreement is subject to FERC's approval. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

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

Revenues from electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule filed with FERC. In 2020 and 2021, our Class A rate schedule (A-40) for electric power sales to our Utility Members consist of three billing components: an energy rate and two demand rates. Utility Member rates for energy and demand are set by our Board, consistent with the provision of reliable cost-based supply of electricity over the long term to our Utility Members. Energy is the physical electricity delivered to our Utility Members. The energy rate was billed based upon a price per kWh of physical energy delivered and the two demand rates (a generation demand and a transmission/delivery demand) were both billed based on the Utility Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays.

Our Class A rate schedule (A-40) was filed at FERC as a "stated rate." While our Board still has authority to determine our rates, those rates, including any change to the rate or rate structure, must be approved by FERC subject to outside comments.

Our Board may from time to time, subject to FERC approval, create new regulatory assets or liabilities or modify the expected recovery period through rates of existing regulatory assets or liabilities. The amounts involved may be material. We continually evaluate options to achieve the goal to lower wholesale rates to our Utility Members.

Tax Status

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. Effective January 1, 2020, we adopted the normalization method for recognizing deferred income taxes pursuant to FERC regulation. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit). Our subsidiaries are not subject to FERC regulation and continue to use a flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues.

Results of Operations

General

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

Weather has a significant effect on the usage of electricity by impacting both the electricity used per hour and the total peak demand for electricity. Consequently, weather has a significant impact on our revenues. Relatively higher summer or lower winter temperatures tend to increase the usage of electricity for heating, air conditioning and irrigation. Extreme winter weather impacted many parts of the United States during mid-February which resulted in significantly higher fuel and purchased power prices. Furthermore, the event affected our renewable generation portfolio as solar and wind generation performed below forecast due to low wind speeds or icing, and were unavailable when we set our year-to-date peak during the weather event. We estimate cost impacts from the mid-February extreme weather event was approximately \$12 million, with almost half of such costs due to energy imbalance charges from other utilities. We have a diverse generation portfolio that allowed us to minimize the financial impacts by using fuel oil at our dual-fuel combustion turbine generating stations in response to the limited availability and record high price of natural gas. Mild weather generally reduces the usage of electricity because heating, air conditioning and irrigation systems are operated less frequently. The amount of precipitation during the growing season (generally May through September) also impacts irrigation use. Other factors affecting our Utility Members' usage of electricity include:

- the amount, size and usage of machinery and electronic equipment;
- the expansion or contraction of operations among our Utility Members' commercial and industrial customers;
- the general growth in population;
- COVID-19 and governmental orders related to COVID-19; and
- economic conditions.

Three months ended March 31, 2021 compared to three months ended March 31, 2020

Operating Revenues

Our operating revenues are primarily derived from electric power sales to our Utility Members and non-member purchasers. Other operating revenue consists primarily of wheeling, transmission, water and coal sales. 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 the three months ended March 31, 2021 and 2020 (dollars in thousands):

	Three Months Ended March 31,		Period-to-period Change	
	2021	2020	Amount	Percent
Operating revenues				
Utility Member electric sales	\$ 272,798	\$ 292,763	\$ (19,965)	(6.8)%
Non-member electric sales	38,174	15,813	22,361	141.4 %
Other	15,000	10,890	4,110	37.7 %
Total operating revenues	\$ 325,972	\$ 319,466	\$ 6,506	2.0 %
Energy sales (in MWh):				
Utility Member electric sales	3,708,132	4,009,791	(301,659)	(7.5)%
Non-member electric sales	250,066	306,677	(56,611)	(18.5)%
	<u>3,958,198</u>	<u>4,316,468</u>	<u>(358,270)</u>	<u>(8.3)%</u>

- Utility Member electric sales decreased, in terms of MWhs sold, primarily due to the withdrawal of DMEA in June 2020 and continued economic impacts of COVID-19 during the quarter, in particular, from our Utility Members' commercial customers. DMEA represented 3.8 percent of Utility Member revenue during the three months ended March 31, 2020. The decrease in Utility Member electric sales revenue caused by lower sales volume was slightly offset by a 1.4 percent higher average price during the three months ended March 31, 2021 when compared to the same period in 2020. The increase in average price was primarily due to increased demand peak from Utility Members during the three months ended March 31, 2021 when compared to the same period in 2020. Revenue from Utility Member electric sales was also impacted by the anticipated two percent proposed settlement rate reduction effective as of March 1, 2021. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.
- Non-member electric sales increased primarily due to rate stabilization measures. In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized \$20.8 million of previously deferred revenue during the three months ended March 31, 2021 compared to none during the same period in 2020. In order to better align with our financial goals, we have begun to recognize deferred revenue on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2021. Excluding the effect of these rate stabilization

measures, non-member electric sales revenue increased \$1.5 million, or 9.7 percent, compared to 2020, primarily due to more favorable pricing for spot market sales during the quarter.

Operating Expenses

Our operating expenses are primarily comprised of the costs that we incur to supply and transmit our Utility Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases and the costs associated with any sales of power to non-members.

The following is a summary of the components of our operating expenses for the three months ended March 31, 2021 and 2020 (dollars in thousands):

	Three Months Ended March 31,		Period-to-period Change	
	2021	2020	Amount	Percent
Operating expenses				
Purchased power	\$ 87,017	\$ 71,015	\$ 16,002	22.5 %
Fuel	60,547	61,069	(522)	(0.9)%
Production	40,901	43,188	(2,287)	(5.3)%
Transmission	44,671	41,540	3,131	7.5 %
General and administrative	14,587	16,215	(1,628)	(10.0)%
Depreciation, amortization and depletion	52,755	47,024	5,731	12.2 %
Coal mining	1,541	2,734	(1,193)	(43.6)%
Other	2,551	7,683	(5,132)	(66.8)%
Total operating expenses	<u>\$ 304,570</u>	<u>\$ 290,468</u>	<u>\$ 14,102</u>	(0.0)%

- Purchased power expense increased primarily due to decreased generation from our generating resources because of favorable market conditions for purchasing power during the three months ended March 31, 2021 compared to the same period in 2020. Generation decreased 24.3 percent during the three months ended March 31, 2021 compared to the same period in 2020. Purchased power increased (in MWhs) 20.4 percent for the three months ended March 31, 2021 compared to the same period in 2020. As a result of the mid-February extreme weather event, we incurred approximately \$4.9 million in energy imbalance charges from other utilities, which is a component of purchased power.
- Production expense decreased primarily due to the postponement, or selective performance, of scheduled maintenance as a result of impacts from the COVID-19 pandemic. Maintenance activities are expected to be performed at later dates.
- Depreciation, amortization and depletion expense increased primarily due to revisions to asset retirement obligation related to the South Taylor pit at the Colowyo Mine during the prior year, which began to depreciate during January 2021.

Financial condition as of March 31, 2021 compared to December 31, 2020

The principal changes in our financial condition from December 31, 2020 to March 31, 2021 were due to increases and decreases in the following:

Assets

- Deposits and advances increased \$5.6 million, or 17.5 percent, to \$37.6 million as of March 31, 2021 compared to \$32.0 million as of December 31, 2020. The increase was primarily due to prepayments of annual insurance, memberships and licenses. These prepayments are being amortized to expense over the term of the related insurance, membership or license period.

Liabilities

- Long-term debt decreased \$52.8 million, or 1.7 percent, to \$3.147 billion as of March 31, 2021 compared to \$3.200 billion as of December 31, 2020 and current maturities of long-term debt increased \$7.0 million, or 8.0 percent, to \$94.6 million as of March 31, 2021 compared to \$87.6 million as of December 31, 2020. The net decrease of \$45.8

million was primarily due to debt payments of \$46.1 million (principally \$41.0 million for the Springerville certificates). In April 2021, we paid off the remaining \$22.0 million balance of the First Mortgage Obligations, Series 2009C.

- Accrued interest increased \$17.8 million, or 64.7 percent, to \$45.3 million as of March 31, 2021 compared to \$27.5 million as of December 31, 2020. The increase was due to accruals for interest due in future periods of \$35.7 million partially offset by interest payments of \$17.9 million.
- Regulatory liabilities decreased \$21.0 million, or 9.3 percent, to \$204.0 million as of March 31, 2021 compared to \$225.0 million as of December 31, 2020. The decrease was primarily due to the recognition of \$20.8 million of previously deferred non-member electric sales revenues. In order to better align with our financial goals, we have begun to recognize deferred revenue on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2021.
- Other deferred credits increased \$17.8 million, or 32.6 percent, to \$72.4 million as of March 31, 2021 compared to \$54.6 million as of December 31, 2020. The increase was primarily due to deposits associated with generator interconnection requests of \$17.1 million. These deposits relate to our revised generator interconnection procedures that were approved by FERC and became effective in the first quarter and the deposits may be returned to the interconnection customer as provided in our revised generator interconnection procedures.

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 March 31, 2021, we had \$109.5 million in cash and cash equivalents. Our committed credit arrangement as of March 31, 2021 is as follows (dollars in thousands):

	Authorized Amount	Available March 31, 2021
Revolving Credit Agreement	\$ 650,000 (1)	\$ 650,000

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

We have a secured Revolving Credit Agreement with aggregate commitments of \$650 million. The Revolving Credit Agreement includes a swingline sublimit of \$100 million, a letter of credit sublimit of \$75 million, and a commercial paper back-up sublimit of \$500 million, of which \$100 million of the swingline sublimit, \$75 million of the letter of credit sublimit, and \$500 million of the commercial paper back-up sublimit remained available as of March 31, 2021.

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 advances will be at base rate loans. We had no outstanding borrowings as of March 31, 2021.

The Revolving Credit Agreement contains customary representations, warranties, covenants, events of default and acceleration, including financial DSR and ECR requirements in line with the covenants contained in our Master Indenture. A violation of these covenants would result in the inability to borrow under the facility.

Under our commercial paper program, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our Revolving Credit Agreement, which was \$500 million at March 31, 2021, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of March 31, 2021, we had no commercial paper outstanding and \$500 million available on the commercial paper back-up sublimit.

We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts

involved may be material. We are mindful of our debt and its maturities and we continually evaluate options to ensure that our balance sheet and capital structure is aligned with our business and the long-term health of our company.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, and the Revolving Credit Agreement.

Cash Flow

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

Three months ended March 31, 2021 compared to three months ended March 31, 2020

Operating activities. Net cash provided by operating activities was \$76.0 million for the three months ended March 31, 2021 compared to \$65.6 million for the same period in 2020, an increase in net cash provided by operating activities of \$10.4 million. The increase was primarily due to deposits associated with generator interconnection requests of \$17.1 million partially offset by lower net margins including noncontrolling interest, an increase prepayments of annual insurance, memberships and licenses.

Investing activities. Net cash used in investing activities was \$32.5 million for the three months ended March 31, 2021 compared to \$42.2 million for the same period in 2020, a decrease in net cash used in investing activities of \$9.7 million. The decrease was primarily due to a reduction in generation and transmission improvements and system upgrades.

Financing activities. Net cash used in financing activities was \$61.3 million for the three months ended March 31, 2021 compared to net cash provided by financing activities of \$48.7 million for the same period in 2020, a decrease in net cash used in financing activities of \$110.0 million. The decrease was primarily due to higher principal payments of long-term debt of \$26.1 million and lower proceeds from issuance of long-term debt in 2021 compared to 2020 (during the first quarter of 2020, we borrowed \$200 million from our Revolving Credit Agreement). These decreases were partially offset by a decrease in short-term borrowings of \$87.6 million.

Capital Expenditures

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility closures, facility costs, market factors and other items affecting our forecasts. After taking into account our Responsible Energy Plan, in the years 2021 through 2025, we forecast that we may invest approximately \$799 million in new facilities and upgrades to our existing facilities.

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

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

Contractual Commitments

Indebtedness. As of March 31, 2021, we had \$3.3 billion in outstanding obligations, including approximately \$3.0 billion of debt outstanding secured on a parity basis under our Master Indenture, one unsecured loan agreement totaling \$17.7 million and the Springerville certificates totaling \$293.0 million (which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease). Our debt secured by the lien of our Master Indenture includes notes payable to CFC and CoBank (with the exception of one unsecured note), the First Mortgage Obligations, Series 2009C, the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, the First Mortgage Bonds, Series 2014E-1 and E-2, First Mortgage Bonds, Series 2016A, 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 the Master Indenture.

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

Coal Purchase Obligations. We have commitments to purchase coal for our generating facilities under long-term contracts that expire between 2021 and 2041. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions. Our coal purchase obligations exclude any purchases we have with our subsidiaries.

Environmental Regulations

We are subject to various federal, state and local laws, rules and regulations with regard to air quality, including greenhouse gases, water quality, and other environmental matters. These environmental laws, rules and regulations are complex and change frequently. For a discussion regarding potential effects on our business from environmental regulations, see also “Item 1 – BUSINESS – ENVIRONMENTAL REGULATION” and “Item 1A – RISK FACTORS” in our annual report on Form 10-K for the year ended December 31, 2020.

Rating Triggers

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s, “BBB+ (stable outlook)” by S&P, and “A- (stable outlook)” by Fitch. Our current short-term ratings are “P-2” by Moody’s, “A-2” by S&P, and “F1” by Fitch.

Our Revolving Credit Agreement includes a pricing grid related to the LIBOR spread, commitment fee and letter of credit fees due under the facility. We also have a term loan agreement that includes a pricing grid related to the LIBOR spread. 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 our credit rating generally being maintained at or above investment grade by S&P and Moody’s. We may enter into additional contracts which may contain similar adequate assurance requirements. If we are required to provide such adequate assurances, we do not believe the amounts will be significant or that they will have a material adverse effect on our financial condition or our future results of operations.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes to market risks during the most recent fiscal quarter from those reported in our annual report on Form 10-K for the year ended December 31, 2020.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective.

Changes in Internal Controls

There have been no changes in our internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information required by this Item is contained in Note 17 to the Unaudited Consolidated Financial Statements in Item 1.

Item 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this quarterly report on Form 10-Q.

Item 6. Exhibits

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
10.12.1	Executive Benefit Restoration Plan of Tri-State Generation and Transmission Association, Inc. - Amendment No. 2, effective May 1, 2021
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 Disclosure Exhibit.
101	XBRL Interactive Data File.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Tri-State Generation and Transmission
Association, Inc.

Date: May 7, 2021

By: /s/ Duane Highley

Duane Highley
Chief Executive Officer

Date: May 7, 2021

/s/ Patrick L. Bridges

Patrick L. Bridges
Senior Vice President/Chief Financial Officer (Principal
Financial Officer)