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 September 30, 2020

OR

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

For the transition period from to

Commission File No. 333-212006

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
(Exact name of registrant as specified in its charter)

Colorado	**84-0464189**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1100 West 116th Avenue **Westminster, Colorado**	**80234**
(Address of principal executive offices)	(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.
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2020

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)

	September 30, 2020 (unaudited)	December 31, 2019
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 6,184,657	$ 6,090,392
Construction work in progress	130,651	164,924
Total electric plant	6,315,308	6,255,316
Less allowances for depreciation and amortization	(2,975,735)	(2,641,470)
Net electric plant	3,339,573	3,613,846
Other plant	415,015	409,051
Less allowances for depreciation, amortization and depletion	(133,587)	(113,607)
Net other plant	281,428	295,444
Total property, plant and equipment	3,621,001	3,909,290
Other assets and investments		
Investments in other associations	159,187	161,945
Investments in and advances to coal mines	19,558	19,681
Restricted cash and investments	4,887	30,516
Other noncurrent assets	8,825	8,654
Total other assets and investments	192,457	220,796
Current assets		
Cash and cash equivalents	164,965	83,070
Restricted cash and investments	199	182
Deposits and advances	31,586	28,434
Accounts receivable—Utility Members	99,420	105,371
Other accounts receivable	25,198	28,039
Coal inventory	55,879	50,191
Materials and supplies	93,342	93,632
Total current assets	470,589	388,919
Deferred charges		
Regulatory assets	717,177	497,279
Prepayment—NRECA Retirement Security Plan	22,833	26,862
Other	58,670	42,672
Total deferred charges	798,680	566,813
Total assets	**$ 5,082,727**	**$ 5,085,818**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 1,029,050	$ 1,031,063
Accumulated other comprehensive loss	(7,604)	(1,518)
Noncontrolling interest	113,425	111,717
Total equity	1,134,871	1,141,262
Long-term debt	3,205,904	3,063,351
Total capitalization	4,340,775	4,204,613
Current liabilities		
Utility Member advances	16,504	18,025
Accounts payable	105,786	99,033
Short-term borrowings	—	252,323
Accrued expenses	29,165	43,761
Current asset retirement obligations	2,840	2,460
Accrued interest	45,830	29,716
Accrued property taxes	28,086	29,129
Current maturities of long-term debt	87,178	81,555
Total current liabilities	315,389	556,002
Deferred credits and other liabilities		
Regulatory liabilities	237,187	122,169
Deferred income tax liability	33,744	58,937
Asset retirement and environmental reclamation obligations	80,303	76,454
Other	56,477	56,399
Total deferred credits and other liabilities	407,711	313,959
Accumulated postretirement benefit and postemployment obligations	18,852	11,244
Total equity and liabilities	**$ 5,082,727**	**$ 5,085,818**

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

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

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Utility Member electric sales	$ 346,769	$ 358,586	$ 926,529	$ 942,175
Non-member electric sales	38,606	28,339	71,044	71,843
Other	16,226	12,128	37,150	39,540
	401,601	399,053	1,034,723	1,053,558
Operating expenses				
Purchased power	103,136	103,525	260,804	252,948
Fuel	65,061	67,374	165,679	204,271
Production	39,698	48,619	122,595	148,457
Transmission	43,989	42,305	127,175	122,329
General and administrative	17,081	12,978	49,337	35,887
Depreciation, amortization and depletion	45,775	40,590	137,110	116,879
Coal mining	4,200	1,675	8,021	7,824
Other	2,691	4,640	13,429	12,154
	321,631	321,706	884,150	900,749
Operating margins	**79,970**	**77,347**	**150,573**	**152,809**
Other income				
Interest	959	1,364	3,248	4,156
Capital credits from cooperatives	1,186	1,186	4,674	4,520
Other income (expense)	197	14,314	348	16,226
	2,342	16,864	8,270	24,902
Interest expense				
Interest	37,673	39,991	114,533	120,754
Interest charged during construction	(1,460)	(1,961)	(5,022)	(6,800)
	36,213	38,030	109,511	113,954
Income tax benefit	(154)	(77)	(484)	(231)
Net margins including noncontrolling interest	46,253	56,258	49,816	63,988
Net margin attributable to noncontrolling interest	(1,424)	(1,113)	(4,164)	(3,239)
Net margins attributable to the Association	**$ 44,829**	**$ 55,145**	**$ 45,652**	**$ 60,749**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Net margins including noncontrolling interest	$ 46,253	$ 56,258	$ 49,816	$ 63,988
Other comprehensive loss:				
Amortization of actuarial loss on postretirement benefit obligation included in net margin	177	(10)	1,287	13
Unrecognized prior service cost	—	—	(7,373)	(214)
Other comprehensive loss	177	(10)	(6,086)	(201)
Comprehensive income including noncontrolling interest	46,430	56,248	43,730	63,787
Net comprehensive income attributable to noncontrolling interest	(1,424)	(1,113)	(4,164)	(3,239)
Comprehensive income attributable to the Association	**$ 45,006**	**$ 55,135**	**$ 39,566**	**$ 60,548**

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 September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Patronage capital equity at beginning of period	$ 984,221	$ 1,021,358	$ 1,031,063	$ 1,015,754
Net margins attributable to the Association	44,829	55,145	45,652	60,749
Retirement of patronage capital	—	—	(47,665)	—
Patronage capital equity at end of period	**1,029,050**	**1,076,503**	**1,029,050**	**1,076,503**
Accumulated other comprehensive income (loss) at beginning of period	(7,781)	184	(1,518)	375
Amortization of prior service cost	177	(10)	1,287	13
Unrecognized prior service cost	—	—	(7,373)	(214)
Accumulated other comprehensive income (loss) at end of period	**(7,604)**	**174**	**(7,604)**	**174**
Noncontrolling interest at beginning of period	113,189	110,841	111,717	110,169
Net comprehensive income attributable to noncontrolling interest	1,424	1,113	4,164	3,239
Equity distribution to noncontrolling interest	(1,188)	(1,352)	(2,456)	(2,806)
Noncontrolling interest at end of period	**113,425**	**110,602**	**113,425**	**110,602**
Total equity at end of period	**$ 1,134,871**	**$ 1,187,279**	**$ 1,134,871**	**$ 1,187,279**

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)

	Nine Months Ended September 30,	
	2020	**2019**
Operating activities		
Net margins including noncontrolling interest	$ 49,816	$ 63,988
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	137,110	116,879
Amortization of intangible asset	—	3,662
Amortization of NRECA Retirement Security Plan prepayment	4,029	4,029
Amortization of debt issuance costs	1,832	1,773
Impairment loss	259,761	37,067
Deferred impairment loss and other closure costs	(268,163)	(37,067)
Deferred membership withdrawal income	110,165	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	2,813	(486)
Changes in operating assets and liabilities:		
Accounts receivable	5,844	(155)
Coal inventory	(5,688)	3,922
Materials and supplies	290	(2,943)
Accounts payable and accrued expenses	9,337	3,418
Accrued interest	16,113	15,691
Accrued property taxes	(1,043)	(282)
Other	(16,323)	(7,581)
Net cash provided by operating activities	**305,893**	**201,915**
Investing activities		
Purchases of plant	(100,821)	(149,396)
Sale of electric plant	26,000	—
Changes in deferred charges	(4,532)	(6,277)
Proceeds from other investments	68	65
Net cash used in investing activities	**(79,285)**	**(155,608)**
Financing activities		
Changes in Utility Member advances	(1,520)	(5,351)
Payments of long-term debt	(277,119)	(91,884)
Proceeds from issuance of long-term debt	425,000	34,910
Debt issuance costs	(637)	(13)
Increase (decrease) in short-term borrowings, net	(252,323)	23,036
Retirement of patronage capital	(60,991)	(11,101)
Equity distribution to noncontrolling interest	(2,456)	(2,806)
Other	(279)	(257)
Net cash used in financing activities	**(170,325)**	**(53,466)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**56,283**	**(7,159)**
Cash, cash equivalents and restricted cash and investments – beginning	**113,768**	**127,590**
Cash, cash equivalents and restricted cash and investments – ending	**$ 170,051**	**$ 120,431**
Supplemental cash flow information:		
Cash paid for interest	$ 97,218	$ 103,782
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ 2,217	$ (873)

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 and Nine Months Ended September 30, 2020 and 2019

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, 2019 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 September 30, 2020, results of operations for the three and nine months ended September 30, 2020 and 2019, and cash flows for the nine months ended September 30, 2020 and 2019 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 ("Class A Member(s)") 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.

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 17 – 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 September 30, 2020 (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 %	$ 395,099	$ 249,804	$ 334
MBPP - Laramie River Station	27.13 %	489,147	301,561	5,075
Total		$ 884,246	$ 551,365	$ 5,409

NOTE 2 – ACCOUNTING FOR RATE REGULATION

We are subject to the accounting requirements related to regulated operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board of Directors (“Board”) if based on regulatory orders or other available evidence, it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs 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. Prior to September 3, 2019, our Board had sole budgetary and rate-setting authority. On September 3, 2019, we became a FERC jurisdictional public utility and our Board’s rate setting authority, including the use of regulatory assets and liabilities, is now subject to FERC approval. Expected recovery of deferred costs and returning deferred credits are based on specific ratemaking decisions by FERC or precedent for each item. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expense concurrent with their recovery through rates.

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

	September 30, **2020**	December 31, **2019**
Regulatory assets		
Deferred income tax expense (1)	$ 33,744	$ 58,937
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	81,996	83,714
Goodwill – J.M. Shafer (3)	47,008	49,145
Goodwill – Colowyo Coal (4)	36,419	37,194
Deferred debt prepayment transaction costs (5)	134,459	140,931
Deferred Holcomb expansion impairment loss (6)	89,988	93,494
Unrecovered plant (7)	293,563	33,864
Total regulatory assets	717,177	497,279
Regulatory liabilities		
Interest rate swap - realized gain (8)	3,391	3,744
Deferred revenues (9)	75,853	75,853
Membership withdrawal (10)	157,943	42,572
Total regulatory liabilities	237,187	122,169
Net regulatory asset	$ 479,990	$ 375,110

(1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.

(2) Represents deferral of the loss on acquisition related to the Springerville Generating Station Unit 3 (“Springerville Unit 3”) prepaid lease expense upon acquiring a controlling interest in the Springerville Unit 3 Partnership LP (“Springerville Partnership”) in 2009. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Utility Members 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. Beginning January 2020, 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. In July 2019, our Board took action for the early retirement of the Nucla Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement of the Nucla Generating Station, we recognized an impairment loss of $37.1 million during the third quarter of 2019. On September 19, 2019, the Nucla Generating Station was officially retired from service. The deferred impairment loss for Nucla Generating Station is being amortized to depreciation, amortization and depletion expense over the 3.3-year period ending in December 2022 and recovered from our Utility Members through rates. In January 2020, our Board approved the early retirement of the Escalante Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement, we recognized an impairment loss of $268.2 million during the first quarter of 2020. The deferred impairment loss for Escalante Generating Station will be amortized to depreciation, amortization and depletion expense beginning in 2021 through the end of 2045, which was the depreciable life of Escalante Generating Station, and is expected to be recovered from our Utility Members through rates. The annual amortization is expected to approximate the former annual Escalante Generating Station depreciation for the remaining life of the asset.
(8) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A and refunded to Utility Members through reduced rates when recognized in future periods.
(9) Represents deferral of the recognition of non-member electric sales revenues. These deferred non-member electric sales revenues will be refunded to Utility Members through reduced rates when recognized in non-member electric sales revenue in future periods.
(10) Represents the deferral of the recognition of other income related to the June 30, 2016 withdrawal of a former Utility Member from membership in us and the June 30, 2020 withdrawal of Delta-Montrose Electric Association ("DMEA") from membership in us. In connection with the DMEA withdrawal, we recognized $110.2 million of other income and $5.2 million of gain on sale of assets which was subsequently deferred. The total deferred membership withdrawal income will be refunded to Utility Members through reduced rates, subject to FERC approval, 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):

	September 30, **2020**	December 31, **2019**
Basin Electric Power Cooperative	$ 114,036	$ 117,368
National Rural Utilities Cooperative Finance Corporation - patronage capital	11,933	11,761
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,885	15,953
CoBank, ACB	11,141	10,201
Western Fuels Association, Inc.	2,302	2,409
Other	3,890	4,253
Investments in other associations	$ 159,187	$ 161,945

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during the nine months ended September 30, 2020 or during 2019.

NOTE 4 – INVESTMENTS IN AND ADVANCES TO COAL MINES

We have direct ownership and investments in coal mines to support our coal generating resources. We, and certain participants in the Yampa Project, are members of Trapper Mining, which is organized as a cooperative and is the owner and operator of the Trapper Mine near Craig, Colorado. Our investment in Trapper Mining is recorded using the equity method. In addition, we have ownership in Western Fuels Association, Inc. (“WFA”), which is an owner of Western Fuels-Wyoming, Inc. (“WFW”), the owner and operator of the Dry Fork Mine near Gillette, Wyoming. Dry Fork Mine provides coal to the Laramie River Generating Station (owned by the participants of MBPP). We, through our undivided interest in the jointly owned facility of MBPP, advance funds to the Dry Fork Mine.

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

	September 30, **2020**	December 31, **2019**
Investment in Trapper Mine	$ 16,279	$ 15,881
Advances to Dry Fork Mine	3,279	3,800
Investments in and advances to coal mines	$ 19,558	$ 19,681

NOTE 5 – CASH, CASH EQUIVALENTS AND RESTRICTED CASH AND INVESTMENTS

We consider highly liquid investments with an original maturity of three months or less to be cash equivalents. The fair value of cash equivalents approximates their carrying values due to their short-term maturity.

Restricted cash and investments represent funds designated by our Board for specific uses and funds restricted by contract or other legal reasons. A portion of the funds 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):

	September 30, **2020**	December 31, **2019**
Cash and cash equivalents	$ 164,965	$ 83,070
Restricted cash and investments - current	199	182
Restricted cash and investments - noncurrent	4,887	30,516
Cash, cash equivalents and restricted cash and investments	$ 170,051	$ 113,768

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

NOTE 6 – 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 13 – 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 nine months ended September 30, 2020, we recognized $0.9 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):

	September 30, **2020**	December 31, **2019**
Accounts receivable - Utility Members	$ 99,420	$ 105,371
Other accounts receivable - trade:		
Non-member electric sales	7,900	4,727
Other	16,615	20,628
Total other accounts receivable - trade	24,515	25,355
Other accounts receivable - nontrade	683	2,684
Total other accounts receivable	$ 25,198	$ 28,039
Contract liabilities (unearned revenue)	$ 6,281	$ 7,041

NOTE 7 – OTHER DEFERRED CHARGES

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

	September 30, **2020**	December 31, **2019**
Preliminary surveys and investigations	$ 23,012	$ 21,261
Advances to operating agents of jointly owned facilities	8,686	3,917
Operating lease right-of-use assets	10,086	7,622
Other	16,886	9,872
Total other deferred charges	$ 58,670	$ 42,672

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 15 – Leases.

NOTE 8 – LONG-TERM DEBT

We have $3.2 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture") except for one unsecured note in the amount of $21.5 million as of September 30, 2020. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a 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 September 30, 2020, we had $650.0 million in availability under the Revolving Credit Agreement.

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

	September 30, 2020	December 31, 2019
Total debt	$ 3,314,353	3,166,472
Less debt issuance costs	(26,218)	(27,412)
Less debt discounts	(9,722)	(9,906)
Plus debt premiums	14,669	15,752
Total debt adjusted for debt issuance costs, discounts and premiums	3,293,082	3,144,906
Less current maturities	(87,178)	(81,555)
Long-term debt	$ 3,205,904	$ 3,063,351

NOTE 9 – SHORT-TERM BORROWINGS

We have a commercial paper program under which we issue unsecured commercial paper in aggregate amounts not exceeding the commercial paper back-up sublimit under our Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our Revolving Credit Agreement. The commercial paper issuances are used to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances vary, but may not exceed 397 days from the date of issue. The commercial paper notes are classified as current and are included in current liabilities as short-term borrowings on our consolidated statements of financial position.

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

	September 30, 2020	December 31, 2019
Commercial paper outstanding, net of discounts	$ —	$ 252,323
Weighted average interest rate	— %	1.88 %

At September 30, 2020, $500.0 million of the commercial paper back-up sublimit remained available under the Revolving Credit Agreement. See Note 8 – Long-Term Debt.

NOTE 10 – 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 post-reclamation monitoring related to the Colowyo Mine, the New Horizon Mine, and the Fort Union Mine. The New Horizon

Mine is currently in post-reclamation monitoring. One pit at the Colowyo Mine began final reclamation in 2018 with the other remaining pits still being actively mined.

Generation: We, including through our undivided interest in jointly owned facilities, 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):

	Nine Months Ended September 30, **2020**
Obligations at beginning of period	$ 78,914
Liabilities incurred	—
Liabilities settled	(824)
Accretion expense	1,895
Change in cash flow estimate	3,158
Total obligations at end of period	$ 83,143
Less current obligations at end of period	(2,840)
Long-term obligations at end of period	$ 80,303

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 11 – 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):

	September 30, **2020**	December 31, **2019**
Transmission easements	$ 20,148	$ 20,549
Operating lease liabilities - noncurrent	1,705	1,846
Contract liabilities (unearned revenue) - noncurrent	3,781	4,217
Customer deposits	7,404	3,015
Financial liabilities - reclamation	10,217	12,091
Other	13,222	14,681
Total other deferred credits and other liabilities	$ 56,477	$ 56,399

In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. $31.2 million will be paid by us for these easements from 2020 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were $20.1 and $20.5 million as of September 30, 2020 and December 31, 2019, 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 15 – 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 12 – 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 September 30, 2020, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles.

The postretirement medical benefit and postemployment medical benefit obligations are determined annually (during the fourth quarter) by an independent actuary and are included in accumulated postretirement benefit and postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	Nine Months Ended September 30, **2020**	
Postretirement medical benefit obligation at beginning of period	$	10,195
Service cost		422
Interest cost		264
Benefit payments (net of contributions by participants)		(465)
Postretirement medical benefit obligation at end of period	$	10,416
Postemployment medical benefit obligation at end of period		375
Total postretirement and postemployment medical obligations at end of period	$	10,791

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):

	Nine Months Ended September 30, **2020**
Accumulated other comprehensive loss at beginning of period	$ (1,387)
Amortization of actuarial (gain) loss into income	11
Amortization of prior service credit into other income	(59)
Accumulated other comprehensive loss at end of period	$ (1,435)

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.

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):

	Nine Months Ended September 30, **2020**
Executive benefit restoration obligation at beginning of period	$ 674
Service cost	312
Interest cost	417
Plan amendments - prior service cost	5,218
Benefit payments	(715)
Actuarial loss	2,155
Executive benefit restoration at end of period	$ 8,061

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 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):

	Nine Months Ended September 30, 2020
Accumulated other comprehensive loss at beginning of period	$ (130)
Plan amendments - prior service cost	(5,218)
Amortization of prior service cost into other income	1,336
Unrecognized actuarial loss	(2,155)
Accumulated other comprehensive loss at end of period	$ (6,167)

NOTE 13 – 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. We had a contract with DMEA that extended through 2040. DMEA withdrew from membership in us on June 30, 2020 and DMEA's contract was assigned by us to DMEA's new third-party power supplier.

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 September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Non-member electric sales:				
Long-term contracts	$ 9,423	$ 12,647	$ 32,817	$ 35,241
Short-term contracts	29,183	15,692	38,227	36,602
Other	16,226	12,128	37,150	39,540
Total non-member electric sales and other operating revenue	$ 54,832	$ 40,467	$ 108,194	$ 111,383

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 and lease revenues, coal sales and revenue from supplying steam and water. Other operating revenue also includes revenue we receive from two of our Non-Utility Members. Wheeling revenue is 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). Steam and water revenue is derived from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station (payments from the customer are received in accordance with the contract terms which is less than 15 days 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. Lease revenue is primarily from a certain power sales arrangement, which expired on June 30, 2019, that was required to be accounted for as an operating lease since the arrangement conveyed the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. We have an obligation to deliver coal and progress of completion toward our performance obligation is measured using the output method. Our performance obligation is completed as coal is delivered.

NOTE 14 – INCOME TAXES

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes. However, in accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Under this regulatory accounting approach, any income tax expense or benefit on our consolidated statements of operations includes only the current provision. This liability method is included in our rate filing accepted by FERC on March 20, 2020; however, FERC may require a different method for the recovery of income taxes. Our consolidated statements of operations included an income tax benefit of $0.5 million for the nine months ended September 30, 2020 and $0.2 million for the comparable period in 2019. These income tax benefits are due to an alternative minimum tax credit refund.

During the first quarter of 2020, we recorded a $19 million decrease in our deferred tax asset valuation allowance due to the deferred tax treatment of an abandonment loss. No further changes to the valuation allowance were needed for the nine-month period ended September 30, 2020.

The Coronavirus Aid, Relief and Economic Security Act (“CARES Act”) was signed into law on March 27, 2020. The CARES Act includes certain corporate income tax provisions which have been evaluated by us. The CARES Act did not have a material impact on our consolidated financial statements.

NOTE 15 – 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 and had a lease agreement for the right to use power generating equipment at Brush Generating Station. Under the power purchase arrangement at the Brush Generating Station that expired on December 31, 2019, we were required to account for the arrangement as an operating lease since it conveys to us the right to direct the use of 70 megawatts at the Brush Generating Station whereby we provide our own natural gas for generation of electricity. We did not renew this power purchase arrangement.

Rent expense for all short-term and long-term operating leases was $1.2 million for the three months ended September 30, 2020 and $1.8 million for the comparable period in 2019. Rent expense for all short-term and long-term operating leases was $2.8 million for the nine months ended September 30, 2020 and $5.4 million for the comparable period in 2019. Rent expense is included in operating expenses on our consolidated statements of operations. As of September 30, 2020, there were no arrangements accounted for as finance leases.

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

	September 30, 2020	December 31, 2019
Operating leases		
Operating lease right-of-use assets	$ 11,464	$ 8,376
Less: Accumulated amortization	(1,378)	(754)
Net operating lease right-of-use assets	$ 10,086	$ 7,622
Operating lease liabilities - current	$ (556)	$ (5,533)
Operating lease liabilities - noncurrent	(1,705)	(1,846)
Total operating lease liabilities	$ (2,261)	$ (7,379)
Operating leases		
Weighted average remaining lease term (years)	7.46	9.5
Weighted average discount rate	3.83%	3.80%

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

Year 1	$ 609
Year 2	444
Year 3	341
Year 4	315
Year 5	196
Thereafter	737
Total lease payments	$ 2,642
Less imputed interest	(381)
Total	$ 2,261

Leasing Arrangements As Lessor

We have lease agreements as lessor for certain operational assets and had a lease agreement as lessor for power generating equipment at the J.M. Shafer Generating Station. Under the power sales arrangement at the J.M. Shafer Generating Station that expired on June 30, 2019, we were required to account for the arrangement as an operating lease since it conveyed to a third party the right to direct the use of 122 megawatts of the 272 megawatt generating capability of the J.M. Shafer Generating Station whereby the third party provided its own natural gas for generation of electricity. The revenue from these lease agreements of $1.8 million and $1.6 million for the three months ended September 30, 2020 and 2019, respectively, and $5.0 million and $10.5 million for the nine months ended September 30, 2020 and 2019, 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 17- Variable Interest Entities. However, as the noncontrolling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded. See Note 14 – Income Taxes.

NOTE 16 – 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.

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):

	September 30, 2020		December 31, 2019	
	Cost	**Estimated Fair Value**	**Cost**	**Estimated Fair Value**
Marketable securities	$ 477	$ 429	$ 715	$ 654

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $102.2 million as of September 30, 2020 and $79.0 million as of December 31, 2019.

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):

	September 30, 2020		December 31, 2019	
	Principal Amount	**Estimated Fair Value**	**Principal Amount**	**Estimated Fair Value**
Total debt	$ 3,314,353	$ 3,926,312	$ 3,166,472	$ 3,608,341

NOTE 17 – 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):

	September 30, **2020**	December 31, **2019**
Net electric plant	$ 762,808	$ 776,411
Noncontrolling interest	113,425	111,717
Long-term debt	342,680	380,867
Accrued interest	3,977	11,050

Our consolidated statements of operations include the following Springerville Partnership expenses for the three and nine months ended September 30, 2020 and 2019 (dollars in thousands):

	September 30,		**September 30,**	
	2020	**2019**	**2020**	**2019**
Depreciation, amortization and depletion	$ 4,535	$ 4,535	$ 13,603	$ 13,603
Interest	5,646	6,281	$ 17,157	19,045

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.

Unconsolidated Variable Interest Entities

Western Fuels Association, Inc. ("WFA"): WFA is a non-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which includes us. WFA, through its ownership in Western Fuels-Wyoming, supplies fuel to MBPP for the use at the Laramie River Station. We also received coal supplies directly from WFA for the Escalante Generating Station in New Mexico. The pricing structure of the coal supply agreements with WFA is designed to recover the mine operating costs of the mine supplying the coal and therefore the coal sales agreements provide the financial support for the mine operations. There is not sufficient equity at risk for WFA to finance its activities without additional financial support. Therefore, WFA is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact WFA's economic performance (acquiring and supplying fuel resources) is held by the members who are represented on the WFA board of directors whose actions require joint approval. Therefore, since there is shared power over the significant activities of WFA, we are not the primary beneficiary of WFA and the entity is not consolidated. Our investment in WFA, accounted for using the cost method, was $2.3 million at September 30, 2020 and $2.4 million at December 31, 2019 and is included in investments in other associations.

Western Fuels – Wyoming ("WFW"): WFW, the owner and operator of the Dry Fork Mine in Gillette, Wyoming, was organized for the purpose of acquiring and supplying coal, through long-term coal supply agreements, to be used in the production of electric energy at the Laramie River Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by Basin). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 27.13 percent undivided interest) own the remaining 25 percent of class BB shares of WFW. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Dry Fork Mine and therefore the coal supply agreements provide the financial support for the operation of the Dry Fork Mine. There is not sufficient equity at risk at WFW for it to finance its activities without additional financial support. Therefore, WFW is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact WFW's economic performance (which includes operations, maintenance and reclamation activities) is shared with the equity interest holders since each member has representation on the WFW board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of WFW and the entity is not consolidated. Our investment in WFW, accounted for using the cost method, was $0.1 million at September 30, 2020 and December 31, 2019 and is included in investments in other associations.

Trapper Mining, Inc. ("Trapper Mining"): Trapper Mining is a cooperative organized for the purpose of mining, selling and delivering coal from the Trapper Mine to the Craig Generating Station Units 1 and 2 through long-term coal supply agreements. Trapper Mining is jointly owned by some of the participants of the Yampa Project. We have a 26.57 percent cooperative member interest in Trapper Mining. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provide the financial support for the operation of the Trapper Mine. There is not sufficient equity at risk for Trapper Mining to finance its activities without the additional financial support. Therefore, Trapper Mining is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact Trapper Mining's economic performance (which includes operations, maintenance and reclamation activities) is shared with the members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of Trapper Mining and the entity is not consolidated. We record our investment in Trapper Mining using the equity method. Our membership interest in Trapper Mining was $16.3 million at September 30, 2020 and $15.9 million at December 31, 2019.

NOTE 18 – 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.

Transmission Agreement: Pursuant to a long-term transmission agreement with another utility, such utility pays for and has firm rights to transfer power and energy across a transmission path in Colorado. Such right to payment and obligation to provide the transfer is borne equally by us and another entity. Due to the current capacity of the transmission path, such utility's firm rights have been curtailed. The utility disputes its obligation to pay due to the current capacity of the transmission path and claims we, along with the other entity, are in breach of such transmission agreement. The utility notified us and the other entity of its intent to arbitrate in accordance with the agreement and claimed damages caused by the alleged breach of approximately $6.9 million, plus interest, attorney fees, and any future damages. The other entity filed a cross-claim against us claiming we are responsible for such entity's share of any damages. The matter was scheduled for arbitration to commence in January 2020. The arbitration was suspended and the parties have reached a resolution of this matter without us incurring any liability. The resolution of this matter is subject to FERC approval. On October 20, 2020, an unexecuted version of an amended and restated transmission agreement to resolve this matter was filed with FERC for approval. It is not possible to predict if FERC will approve this agreement.

FERC Tariff and Declaratory Order: At our July 2019 Board meeting, our Board authorized us to take action to place us under wholesale rate regulation by FERC. On September 3, 2019, a membership agreement with a Non-Utility Member, MIECO, Inc., became effective. The admission of the new Non-Utility Member that was not an electric cooperative or governmental entity resulted in us no longer being exempt from FERC wholesale rate regulation pursuant to the Federal Power Act ("FPA"). In December 2019, we filed our tariff filings, including our stated rate cost of service filing, market based rate authorization, and transmission Open Access Transmission Tariff. The request was made to FERC to make the new tariffs retroactive to September 3, 2019. In addition, on December 23, 2019, we filed our Petition for Declaratory Order ("PDO") with FERC asking FERC to confirm our jurisdiction under the FPA and that FERC's jurisdiction preempts the jurisdiction of the Colorado Public Utilities Commission ("COPUC") to address any rate related issues.

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

On April 13, 2020, we filed a request for rehearing limited to the issue of preemption of the COPUC related to the contract termination payment amount as described in our PDO. Requests for rehearing related to both the PDO and tariff filings were filed with FERC by other parties. On August 28, 2020, FERC issued an order on rehearing related to our 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 ("August 28 Order"). The August 28 Order also set aside requests for rehearing filed with FERC by other parties related to the PDO. Requests for rehearing related to FERC's August 28 Order were filed with FERC by two of our Utility Members. On October 28, 2020, FERC issued an order denying the requests for rehearing filed by two of our Utility Members.

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. Requests for rehearing related to this FERC order has been filed with FERC by one of our Utility Members.

On July 13, 2020, we filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit ("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 PDO and FERC's order granting rehearings for further consideration. Petitions for review related to both the PDO and tariff filings have been filed with the D.C. Circuit Court of Appeals by other parties. On September 18, 2020, FERC filed to hold the appeals in abeyance. On September 29, 2020, an order was filed considering the motion to hold the case in abeyance, directing the parties to file motions to govern future proceedings by January 11, 2021.

It is not possible to predict if FERC will require us to refund amounts to our customers for sales after March 26, 2020, if FERC will approve our current practices regarding use of regulatory assets are just and reasonable, or to estimate any liability associated with these matters. In addition, we cannot predict the outcome of the 206 proceedings, any requests for rehearing filed with FERC, or our petition for review or any other petitions for review filed with the D.C. Circuit Court of Appeals.

United Adams District Court Complaint: On May 4, 2020, United Power, Inc. ("United") filed a Complaint for Declaratory Judgement and Damages in the Adams County District Court 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, 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's allegations and request for relief, and asked the court to dismiss United's claims. We asserted counterclaims against United, and are seeking relief from United'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 filed its response on July 30, 2020. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

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 member systems, or 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, or 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, or Non-Utility Members. Our Utility Members and Non-Utility Members are collectively referred to as our "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 Federal Power Act, or 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 4,317 megawatts, or MWs, of which approximately 1,059 MWs comes from renewables. In 2019, 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 13.4 million megawatt hours, or MWhs, for the nine months ended September 30, 2020, of which 91.2 percent was to Utility Members. Total revenue from electric sales was $997.6 million for the nine months ended September 30, 2020 of which 92.9 percent was from Utility Member sales. Our results for the nine months ended September 30, 2020 were primarily impacted by seasonal weather changes 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 $15.6 million, or 1.7 percent, primarily due to the withdrawal of a Class A Member in June 2020 and pandemic related issues as many commercial operations continued to be closed or severely reduced.
- Fuel expense decreased $38.6 million, or 18.9 percent, primarily due to fluctuations in fuel prices and decreased generation from our generating stations in response to overall decreased demand. Further contributing to decrease in fuel expense, was an environmental obligation related to the New Horizon Mine which was recognized in the prior year.
- Production expense decreased $25.9 million, or 17.4 percent, primarily due to the postponement, or selective performance, of scheduled maintenance as a result of impacts from the COVID-19 pandemic.

Our Bylaws and Wholesale Electric Service Contracts

Pursuant to our Bylaws, each Utility Member is required to purchase from us the electric power and energy provided in the wholesale electric service contract with such Utility Member. Our wholesale electric service contracts with our 42 Utility Members extend through 2050. These 42 contracts are substantially similar and are subject to automatic extension thereafter until either party provides at least a two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Utility Member and obligates the Utility Member to purchase and receive, at least 95 percent of its electric power requirements from us. 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 September 30, 2020, 20 Utility Members have enrolled in this program with capacity totaling approximately 131 MWs of which 120 MWs are in operation. Delta-Montrose Electric Association, or DMEA, withdrew from membership in us in June 2020 and DMEA's contract was assigned by us to DMEA's new third-party power supplier.

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, in March 2020, our Board of Directors, or Board, established two classes of Utility Members: Class A - Utility Full Requirements and Class B – Utility Partial Requirements. Both classes of membership are full-requirements transmission Utility Members with the term of all contracts remaining unchanged and continuing to extend through 2050. Class A Members that elect to become Class B members shall be subject to a buy-down payment. In April 2020, the Board approved the terms and conditions for a buy-down payment methodology for a Class A Member to become a Class B member that will make other Utility Members financially whole. In July 2020, we filed with the Federal Energy Regulatory Commission, or FERC, the Board approved buy-down payment methodology. In September 2020, FERC accepted our buy-down payment methodology and referred it to FERC's hearing and settlement judge procedures. FERC's hearing and settlement judge procedures were also consolidated with FERC's hearing and settlement judge procedures for our contract termination payment methodology discussed below. In October 2020, our Board approved the partial requirements form contracts and associated partial requirements policies and started the implementation process by providing a ninety-day notice prior to the start of the open season. In January 2021, Utility Members will have approximately one week to express their intent to transition to partial requirements contracts by submitting an application requesting an allocation of the 300 MW system-wide limit. Under the new partial requirements membership construct, Utility Members can request to self-supply up to approximately 50 percent of their load requirements, subject to availability in the open season, in addition to the current 5 percent self-supply provision under the wholesale electric service contract. The capacity available for allocation in the open season represents 10 percent of our system peak demand.

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 been had the Utility Member not terminated. Any termination of a Utility Member wholesale electric service contract shall continue to require Board approval. In April 2020, we filed with FERC the Board approved contract termination payment methodology. In June 2020, FERC accepted our contract termination payment methodology and referred it to FERC's hearing and settlement judge procedures. Two of our Utility Member filed requests for rehearing. FERC subsequently issued an order denying the two Utility Members requests for rehearing. In October 2020, a Utility Member filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit related to FERC's acceptance of the contract termination payment methodology.

In November 2019, La Plata Electric Association, Inc., or LPEA, filed a formal complaint with the Colorado Public Utilities Commission, or COPUC, alleging that we hindered LPEA's ability to seek withdrawal from us. In November 2019, United Power, Inc., or United, filed a formal complaint with the COPUC alleging that we hindered United's ability to explore its power supply options by either withdrawing from us or continuing as a Utility Member under a partial requirements contract. The COPUC consolidated the proceeding. On July 10, 2020, the administrative law judge issued a recommended decision, but the COPUC on its own motion stayed the recommended decision. On October 22, 2020, the COPUC determined that COPUC's jurisdiction over United and LPEA's complaints was preempted by FERC and dismissed both complaints without prejudice. See "LEGAL PROCEEDINGS."

In May 2020, United filed a Complaint for Declaratory Judgement and Damages in the Adams County District Court 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, 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’s allegations and request for relief. We asserted counterclaims against United, and requested declaratory judgements on certain matters. On June 20, 2020, the three Non-Utility Members filed a joint motion to dismiss. See “Item 1 - LEGAL PROCEEDINGS” in our quarterly report on Form 10-Q for the three and six months ended June 30, 2020.

Responsible Energy Plan

In July 2019, we announced that we are pursuing a Responsible Energy Plan to transition to a cleaner generation portfolio while ensuring reliability, increasing Utility Member flexibility, all with a goal to lower wholesale rates to our Utility Members. In January 2020, we announced the actions of our Responsible Energy Plan, which advance our cleaner generation portfolio and programs to serve our Utility Members. Some of the actions of the Responsible Energy Plan include:

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

For further information regarding our Responsible Energy Plan, see “Item 1 – BUSINESS — MEMBERS” in our annual report on Form 10-K for the year ended December 31, 2019.

Early Retirements of Generating Facilities

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

In the first quarter of 2020, in accordance with accounting requirements, we recognized an impairment loss of $268.2 million associated with the early retirement of Escalante Generating Station. Our Board approved the deferral of such impairment loss as a regulatory asset. This loss will be amortized to depreciation, amortization and depletion expense beginning in 2021 through the end of 2045, which was the depreciable life of Escalante Generating Station, and is expected to be recovered from our Utility Members through rates. Such deferral and recovery was approved by FERC during the third quarter of 2020. Craig Generating Station Units 2 and 3 continue to be depreciated over the last rate study end lives of 2039 and 2044. Once it becomes probable that FERC will approve the impairment and recovery of unrecovered depreciation associated with the closure of Craig Generating Station Units 2 and 3, then the expected unrecovered depreciation at the time of the closure will be impaired and recovered from our Utility Members through rates. The net book value of Craig Generating Station Units 2 and 3 was $430.3 million as of September 30, 2020. The shortened life of Colowyo Mine increases annual depreciation, amortization and depletion expense in the amount of approximately $12.7 million.

In connection with such early retirements, our Board continues to evaluate the creation of 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.

COVID-19 Impacts

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

We are intensely focused on safely delivering power to our Utility Members and ensuring the reliability of the regional power grid, protecting our employees' health, and supporting state and national directives to stem the spread of COVID-19 in our communities. We have activated established programs and procedures to mitigate the impacts of pandemics and protect our employees from communicable diseases. Our Crisis Management Team, representing all functions of our operations, is actively assessing potential impacts to our operations and taking actions that mitigate those impacts. These actions include: ensuring our critical generation, transmission and operations teams are staffed and have the resources needed to safely operate our power system; implementing best practices to protect employees from the spread of COVID-19, including achieving social distancing for employees through work from home programs; and postponing in-person meetings with our membership in accordance with public health directives, including delaying our annual membership meeting to August 2020 and holding such meeting virtually. We have also supported COVID-19 pandemic relief and recover funds in each of the four states of our Utility Members, including donations totaling $200,000.

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

The economic impacts of the COVID-19 pandemic and the various government measures related to COVID-19 have caused a significant slowdown in certain sectors of the economy, including oil and gas, and a corresponding increase in unemployment. We have experienced changes in the load patterns of our Utility Members. We continue to monitor the impacts of COVID-19. The full extent to which the COVID-19 pandemic may ultimately impact our results of operations depends on numerous evolving factors, which are highly uncertain and difficult to predict, including new information concerning recent increases in cases of COVID-19, the scope of the recent increases in COVID-19 and the actions to further contain the virus or treat its impact, and to what extent normal economic and operating conditions can resume, among others. We currently believe that we have sufficient liquidity to meet our anticipated capital and operating requirements, and we completed two long-term debt transactions in June 2020 with proceeds totaling $225 million. It is reasonably possible, however, that disruption and volatility in the global capital markets may materially increase the cost of capital in the future. The full impact on our results of operations, financial condition, and cash flows cannot be reasonably estimated at this time. 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 September 30, 2020, 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, 2019.

Factors Affecting Results

Master Indenture

As of September 30, 2020, we had approximately $3.0 billion of secured indebtedness outstanding under our indenture dated effective as of December 15, 1999, or Master Indenture, between us and Wells Fargo Bank, National Association, as trustee. 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

Debt Service Ratio (as defined in the Master Indenture), or 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 Equity to Capitalization Ratio, or ECR, (as defined in the Master Indenture) of at least 18 percent at the end of each fiscal year.

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 $463.2 million of patronage capital to our Members, including the $47.7 million we retired and DMEA forfeited as part of DMEA's withdrawal from membership in us on June 30, 2020.

Pursuant to our Board Policy for Financial Goals and Capital Credits, we set rates to achieve a DSR and ECR in excess of the requirements under our Master Indenture in order to mitigate the risk of potential negative variances between budgeted margins and actual margins. This policy was revised in 2018 to establish a goal of our Board to either defer revenues and incomes as a regulatory liability or recognize previously deferred revenues and incomes in an amount that will result in a DSR equal to a DSR goal for the applicable year as set forth in the policy. As allowed by our Bylaws, the deferral or recognition of previously deferred revenues and income is for the purpose of stabilizing margins and limiting rate increases from year to year. In association with the above change, our Board Policy for Financial Goals and Capital Credits was also revised to provide that our Board will endeavor to fund an internally restricted cash account for the purpose of cash funding deferred revenues and incomes held as regulatory liabilities. The amount of cash our Board may internally restrict each year is not based upon the amount of revenue and income deferred.

Rates and Regulation

At our July 2019 Board meeting, because of increased pressure by states to regulate our rates and charges, our Board authorized us to take action to place us under wholesale rate regulation by FERC. By the addition of non-cooperative members in 2019 and specifically by the addition of MIECO, Inc. as a Non-Utility Member on September 3, 2019. On the same date, we became FERC jurisdictional for our Utility Member rates, transmission service, and our market based rates. In December 2019, we filed our tariff filings, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. On March 20, 2020, FERC issued orders regarding 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 for our Utility Member rates and our transmission service rates prior to March 26, 2020. FERC did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered a 206 proceeding to determine the justness and reasonableness of our rates, including our Class A wholesale rate schedule referenced below, and wholesale electric service contracts. The tariff rates were referred to an administrative law judge to encourage settlement of material issues and to hold a hearing if settlement is not reached. The settlement proceedings are continuing and settlement offers are being exchanged under the FERC administrative law judge's guidance and in participation with FERC staff. A fourth settlement conference is scheduled for December 21, 2020. Any refunds to the applicable tariff rates would only apply after March 26, 2020. See "LEGAL PROCEEDINGS."

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 2019 and 2020, 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.

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

Our Board may from time to time, subject to FERC approval, create new regulatory assets or liabilities or modify the expected recovery period through rates of existing regulatory assets or liabilities. The amounts involved may be material. We continually evaluate options to achieve the goal 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. However, in accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Under this regulatory accounting approach, any income tax expense or benefit on our consolidated statements of operations includes only the current portion.

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. 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 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 September 30, 2020 compared to three months ended September 30, 2019

Operating Revenues

Our operating revenues are primarily derived from electric power sales to our Utility Members and non-member purchasers. Other operating revenue consists primarily of wheeling, transmission and lease revenues, coal sales and revenue from supplying steam and water. Other operating revenue also includes revenue we receive from two of our Non-Utility Members. The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the three months ended September 30, 2020 and 2019 (dollars in thousands):

	Three Months Ended September 30,		Period-to-period Change	
	2020	2019	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 346,769	$ 358,586	$ (11,817)	(3.3)%
Non-member electric sales	38,606	28,339	10,267	36.2%
Other	16,226	12,128	4,098	33.8%
Total operating revenues	$ 401,601	$ 399,053	$ 2,548	0.6%
Energy sales (in MWh):				
Utility Member electric sales	4,512,087	4,625,494	(113,407)	(2.5)%
Non-member electric sales	533,360	549,427	(16,067)	(2.9)%
	5,045,447	5,174,921	(129,474)	(2.5)%

- Utility Member electric sales decreased, in terms of MWhs sold, primarily due to the withdrawal of DMEA in June 2020 and continued economic impacts of COVID-19 during the quarter, in particular, from our Utility Members' commercial customers. Revenue from Utility Member electric sales also decreased due to a 0.9 percent lower average price during the three months ended September 30, 2020 when compared to the same period in 2019. The decrease in average price was primarily due to decreased demand peak from Utility Members during the three months ended September 30, 2020 when compared to the same period in 2019.
- Non-member electric sales increased primarily due to strong open market sales during the three months ended September 30, 2020 when compared to the same period in 2019. While non-member electric sales decreased in terms of MWhs, the average price for the three months ended September 30, 2020 was 51.1 percent higher when compared to the same period in 2019. Increased prices were due in part to impacts from the western fires, causing low production of power in affected states and the need to import replacement power from neighboring states.
- Other operating revenues increased primarily due to increased transmission for others.

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 September 30, 2020 and 2019 (dollars in thousands):

	Three Months Ended September 30,		Period-to-period Change	
	2020	2019	Amount	Percent
Operating expenses				
Purchased power	$ 103,136	$ 103,525	$ (389)	(0.4)%
Fuel	65,061	67,374	(2,313)	(3.4)%
Production	39,698	48,619	(8,921)	(18.3)%
Transmission	43,989	42,305	1,684	4.0%
General and administrative	17,081	12,978	4,103	31.6%
Depreciation, amortization and depletion	45,775	40,590	5,185	12.8%
Coal mining	4,200	1,675	2,525	150.7%
Other	2,691	4,640	(1,949)	(42.0)%
Total operating expenses	$ 321,631	$ 321,706	$ (75)	(0.0)%

- 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.
- General and administrative expense increased primarily due to an increase in outside professional services, increased regulatory commission costs, as well as an overall increase in expenses related to general and administration labor and benefits.
- Depreciation, amortization and depletion expense increased primarily due to increased depreciation related to the Collom development, accelerated depletion on the coal reserves at the Colowyo Mine and a change in asset depreciable lives from 2044 to 2030 as a result of the planned early retirement of the Colowyo Mine.

Nine months ended September 30, 2020 compared to nine months ended September 30, 2019

Operating Revenues

The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the nine months ended September 30, 2020 and 2019 (dollars in thousands):

	Nine Months Ended September 30,		Period-to-period Change	
	2020	2019	Amount	Percent
Operating revenues				
Member electric sales	$ 926,529	$ 942,175	$ (15,646)	(1.7)%
Non-member electric sales	71,044	71,843	(799)	(1.1)%
Other	37,150	39,540	(2,390)	(6.0)%
Total operating revenues	$ 1,034,723	$ 1,053,558	$ (18,835)	(1.8)%
Energy sales (in MWh):				
Member electric sales	12,246,955	12,393,692	(146,737)	(1.2)%
Non-member electric sales	1,177,370	1,444,087	(266,717)	(18.5)%
	13,424,325	13,837,779	(413,454)	(3.0)%

- Utility Member electric sales decreased, in terms of MWhs sold, primarily due to the withdrawal of DMEA and a slowdown in certain sectors of the economy from the impacts of COVID-19, in particular, from our Utility Members' commercial members. Revenue from Utility Member electric sales further decreased due to a half percent lower average price for the nine months ended September 30, 2020 when compared to the same period in 2019. The decrease in average price was primarily due to decreased demand peak from Utility Members during the nine months ended September 30, 2020 when compared to the same period in 2019.
- Other operating revenues decreased primarily due to the expiration of leasing arrangement as a lessor on June 30, 2019. Under the agreement, we provided for the use of power generating equipment at the J.M. Shafer Generating Station.

Operating Expenses

The following is a summary of the components of our operating expenses for the nine months ended September 30, 2020 and 2019 (dollars in thousands):

	Nine Months Ended September 30,		Period-to-period Change	
	2020	2019	Amount	Percent
Operating expenses				
Purchased power	$ 260,804	$ 252,948	$ 7,856	3.1%
Fuel	165,679	204,271	(38,592)	(18.9)%
Production	122,595	148,457	(25,862)	(17.4)%
Transmission	127,175	122,329	4,846	4.0%
General and administrative	49,337	35,887	13,450	37.5%
Depreciation, amortization and depletion	137,110	116,879	20,231	17.3%
Coal mining	8,021	7,824	197	2.5%
Other	13,429	12,154	1,275	10.5%
Total operating expenses	$ 884,150	$ 900,749	$ (16,599)	(1.8)%

- Purchased power expense increased primarily due to favorable market conditions for purchasing power resulting in lower generation from our generating stations. Purchased power increased (in MWhs) 7.2 percent for the nine months ended September 30, 2020 when compared to the same period in 2019. The increase was partially offset by a 4.7 percent decrease in the average price of purchased power during the nine months ended September 30, 2020 when compared to the same period in 2019.
- Fuel expense decreased primarily due to lower generation from our generating facilities, fluctuations in fuel prices, and overall decreased demand as a result of more mild weather, and impacts from COVID-19 for the nine months ended September 30, 2020 when compared to the same period in 2019. Also included in fuel expense during the nine months ended September 30, 2019 compared the same period in 2020 was an additional environmental obligation of $9.9 million due to the anticipated revision to the New Horizon Mine reclamation plan to accommodate an alternative post mine land use, including construction of a pond, necessary for final mine reclamation.
- Production expense decreased primarily due to the postponement, or selective performance, of scheduled maintenance activities as a result of impacts from the COVID-19. Maintenance activities are expected to be performed at later dates.
- General and administrative expense increased primarily due to an increase in outside professional services, increased regulatory commission costs, fewer recoveries of general and administrative costs from joint project activities, as well as an overall increase in expenses related to general and administration labor and benefits.
- Depreciation, amortization, and depletion expense increased primarily due to increased depreciation related to the Collom development, accelerated depletion on the coal reserves at the Colowyo Mine and a change in asset depreciable lives from 2044 to 2030 as a result of the planned early retirement of the Colowyo Mine. Additionally, deferred impairment costs related to the Holcomb Generating Station began to be amortized in January 2020.

Financial condition as of September 30, 2020 compared to December 31, 2019

The principal changes in our financial condition from December 31, 2019 to September 30, 2020 were due to increases and decreases in the following:

Assets

- Cash and cash equivalents increased $81.9 million, or 98.6 percent, to $165.0 million as of September 30, 2020 compared to $83.1 million as of December 31, 2019. The increase was primarily due to proceeds from the issuance of long-term debt of $425 million ($125 million under our First Mortgage Obligations, Series 2020A with CoBank, ACB, or CoBank, $100 million under our First Mortgage Obligations, Series 2020B with National Rural Utilities Cooperative Finance Corporation, or CFC, and $200 million under our secured revolving credit facility with CFC, as lead arranger and administrative agent, or the Revolving Credit Agreement) and proceeds of $88.5 million related to the DMEA withdrawal. These increases in cash and cash equivalents were partially offset by lower short-term borrowings and higher principal payments of long-term debt.
- Restricted cash and investments decreased $25.6 million, or 83.4 percent, to $5.1 million as of September 30, 2020 compared to $30.7 million as of December 31, 2019. The decrease was primarily due to the unrestricting by our Board of restricted cash related to deferred revenue in response to volatile market conditions.
- Regulatory assets increased $219.9 million, or 44.2 percent, to $717.2 million as of September 30, 2020 compared to $497.3 million as of December 31, 2019. The increase was primarily due to the deferral of the $268.2 million impairment loss (including $259.8 million of impaired assets and $8.4 million of deferred severance) related to the early retirement of the Escalante Generating Station, which is expected to be retired by the end of 2020. This increase was partially offset by a decrease of $25.0 million in the deferred income tax valuation allowance related to the Holcomb abandonment tax loss and amortization of $23.1 million to depreciation, amortization and depletion expense and recovered from our Utility Members through rates.

Liabilities

- Long-term debt increased $142.6 million, or 4.7 percent, to $3.206 billion as of September 30, 2020 compared to $3.063 billion as of December 31, 2019 and current maturities of long-term debt increased $5.6 million, or 6.9 percent, to $87.2 million as of September 30, 2020 compared to $81.6 million as of December 31, 2019. The total increase of $148.2 million was due to proceeds from issuance of long-term debt of $425.0 million ($125 million from CoBank, $100 million from CFC, and $200 million under our Revolving Credit Agreement) partially offset by debt payments of $277.1 million (primarily $200.0 million for our Revolving Credit Agreement, $37.2 million for the Springerville certificates and $22.0 million for the First Mortgage Obligations, Series 2009C).
- Short-term borrowings decreased $252.3 million, or 100.0 percent, to $0 as of September 30, 2020 compared to $252.3 million as of December 31, 2019. The decrease was due to a temporary market disruption in the commercial paper market which began around March 16, 2020 and continued through early April. During that period of time which saw elevated Tier 2 borrowing rates and shortened tenors, we borrowed under our Revolving Credit Agreement in the amount of $200 million and paid down the commercial paper by $200 million. On June 24, 2020 we entered into the First Mortgage Obligations, Series 2020A in the amount of $125 million with CoBank as well as the First Mortgage Obligations, Series 2020B in the amount of $100 million with CFC. Proceeds from these two borrowings were used to repay all remaining outstanding commercial paper that came due through July 15, 2020. Additionally, proceeds paid off the remaining Revolving Credit Agreement borrowing in the amount of $125 million that came due on September 24, 2020.
- Accrued interest increased $16.1 million, or 54.2 percent, to $45.8 million as of September 30, 2020 compared to $29.7 million as of December 31, 2019. The increase was due to accruals for interest due in future periods of $113.2 million partially offset by interest payments of $97.1 million.
- Regulatory liabilities increased $115.0 million, or 94.2 percent, to $237.2 million as of September 30, 2020 compared to $122.2 million as of December 31, 2019. The increase was primarily due to the deferral of the

recognition of $110.2 million of other income and $5.2 million gain on sale of assets in connection with the June 30, 2020 withdrawal of DMEA from membership in us.

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 September 30, 2020, we had $165.0 million in cash and cash equivalents. Our committed credit arrangement as of September 30, 2020 is as follows (dollars in thousands):

	Authorized Amount	Available September 30, 2020
Revolving Credit Agreement	$ 650,000 (1)	$ 650,000

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

We have a secured Revolving Credit Agreement with aggregate commitments of $650 million. The Revolving Credit Agreement includes a swingline sublimit of $100 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million, of which $100 million of the swingline sublimit, $75 million of the letter of credit sublimit, and $500 million of the commercial paper back-up sublimit remained available as of September 30, 2020.

The Revolving Credit Agreement is secured under the Master Indenture and has a maturity date of April 25, 2023, unless extended as provided therein. Funds advanced under the Revolving Credit Agreement are either LIBOR rate loans or base rate loans, at our option. LIBOR rate loans bear interest at the adjusted LIBOR rate for the term of the advance plus a margin (currently 1.125 percent) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (currently 0.125 percent) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00 percent, (b) the prime rate, and (c) the one-month LIBOR rate plus 1.00 percent. Upon discontinuation of the LIBOR rate, the Revolving Credit Agreement provides for CFC and us to endeavor to establish an alternative rate that gives due consideration to the then prevailing market convention for determining a rate of interest for syndicated loans in the United States. Upon discontinuation of the LIBOR rate and if no alternative rate has been established by CFC and us, all funds advances will be at base rate loans. On March 24, 2020, we borrowed $125 million in LIBOR rate loans under our Revolving Credit Agreement, which was repaid on September 24, 2020.

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

Under our commercial paper program, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our Revolving Credit Agreement, which was $500 million at September 30, 2020, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of September 30, 2020, we had no commercial paper outstanding and $500 million available on the commercial paper back-up sublimit.

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

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

Cash Flow

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

Nine months ended September 30, 2020 compared to nine months ended September 30, 2019

Operating activities. Net cash provided by operating activities was $305.9 million for the nine months ended September 30, 20200 compared to $201.9 million for the same period in 2019, an increase in net cash provided by operating activities of $104.0 million. The increase was primarily due to proceeds of $88.5 million related to the DMEA withdrawal and the timing of payment of trade and purchased power payables.

Investing activities. Net cash used in investing activities was $79.3 million for the nine months ended September 30, 2020 compared to $155.6 million for the same period in 2019, a decrease in net cash used in investing activities of $76.3 million. The decrease was primarily due to proceeds from the sale of electric plant related to the DMEA withdrawal and a reduction in generation and transmission improvements and system upgrades for the nine months ended September 30, 2020 compared to the same period in 2019.

Financing activities. Net cash used in financing activities was $170.3 million for the nine months ended September 30, 2020 compared to $53.5 million for the same period in 2019, an increase in net cash used in financing activities of $116.8 million. The increase was primarily due to higher principal payments of long-term debt of $185.2 million, a decrease in short-term borrowings of $275.4 million and higher patronage capital retirements to our Members of $49.9 million in 2020 compared to 2019 (on June 30, 2020, we retired $47.7 million of patronage capital in connection with DMEA’s withdrawal from membership in us). These increases in net cash used in financing activities were partially offset by higher proceeds from issuance of long-term debt of $390.1 million in 2020 compared to 2019 (during 2020, we issued $125 million from the First Mortgage Obligations, Series 2020A, $100 million from the First Mortgage Obligations, Series 2020B and $200 million from our Revolving Credit Agreement).

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, but without taking into account any changes due to COVID-19, in the years 2020 through 2024, we forecast that we may invest approximately $877 million in new facilities and upgrades to our existing facilities.

Our actual capital expenditures depend on a variety of factors, including assumptions related to our Responsible Energy 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 September 30, 2020, we had $3.3 billion in outstanding obligations, including approximately $3.0 billion of debt outstanding secured on a parity basis under our Master Indenture, one unsecured loan agreement totaling $21.5 million and the Springerville certificates totaling $334.0 million (which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease). Our debt secured by the lien of our Master Indenture includes notes payable to CFC and CoBank (with the exception of one unsecured note), the First Mortgage Obligations, Series 2009C, the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, the First Mortgage Bonds, Series 2014E-1 and E-2, 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 and the Collom pit at Colowyo Mine.

Coal Purchase Obligations. We have commitments to purchase coal for our generating facilities under long-term contracts that expire between 2020 and 2041. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions. Our coal purchase obligations exclude any purchases we have with our subsidiaries.

Environmental Regulations and Litigation

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. The following are recent developments relating to environmental regulations and litigation that may impact us.

Collom Air Permit

On July 25, 2018, the Center for Biological Diversity and Sierra Club filed a complaint against the Colorado Department of Public Health and Environment, or the CDPHE, in opposition to CDPHE's issuance of an air permit for construction and operation of the Collom pit at the Colowyo Mine. On February 14, 2019, the court issued a stay of the case proceedings while CDPHE processed a permit revision. On November 7, 2019, the Collom air permit revision was issued by CDPHE. On December 11, 2019, the Center for Biological Diversity and Sierra Club filed a new case challenging the CDPHE's issuance of the Collom air permit revision. We filed a motion to intervene as an intervenor-defendant on January 28, 2020. On October 6, 2020, the oral arguments occurred. On October 21, 2020, the judge issued an order affirming the CDPHE's issuance of the minor source construction air permit to Collom.

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, 2019.

Rating Triggers

Our current senior secured ratings are "A3 (stable outlook)" by Moody's Investors Services, or Moody's, "A- (negative outlook)" by Standard & Poor's Global Ratings, or S&P, and "A- (stable outlook)" by Fitch Rating, Inc., or 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.

Off Balance Sheet Arrangements

We have no off-balance sheet arrangements.

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, 2019.

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

Other than as disclosed below, there have been no material changes from the legal proceedings disclosed in “Item 3 – LEGAL PROCEEDINGS” in our annual report on Form 10-K for the year ended December 31, 2019 and updated in Item 1 – LEGAL PROCEEDINGS” in our quarterly report on Form 10-Q for the three and six months ended June 30, 2020.

LPEA and United 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 filed a formal complaint with the COPUC, alleging that we hindered United’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 filed a Joint Motion to Lodge FERC’s August 28, 2020 order on rehearing in which FERC reconsidered and modified its March 20, 2020 order finding that the COPUC’s jurisdiction over United and LPEA’s complaints was preempted as of September 3, 2019, 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 and LPEA's complaints was preempted by FERC, the COPUC does not have jurisdiction over corporate law matters, and dismissed both complaints without prejudice.

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, or PDO, with FERC asking FERC to confirm our jurisdiction under the FPA and that FERC's jurisdiction preempts the jurisdiction of the COPUC to address any rate related issues, including the complaints filed by United and LPEA, EL20-16-000.

On March 20, 2020, FERC issued orders regarding our PDO and our tariff filings. FERC's orders generally accepted our tariff filings and recognized that we became FERC jurisdictional on September 3, 2019, but did not make the tariffs retroactive to September 3, 2019. However, FERC specifically provided that no refunds are due on our Utility Member rates and our transmission service rates prior to March 26, 2020. FERC did not impose any civil penalties on us. FERC also did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered a 206 proceeding to determine the justness and reasonableness of our rates and wholesale electric service contracts. FERC also rejected our Board Policy 115, or BP 115, and member project contracts related our Utility Member's election to provide up to 5 percent of its electric power requirements pursuant to their wholesale electric service contracts on the grounds that the initial filing was incomplete without Board Policy 101, or BP 101, related to the self-supply in excess of the 5 percent annual allowance. The tariff rates were referred to an administrative law judge to encourage settlement of material issues and to hold a hearing if settlement is not reached. The settlement proceedings are continuing and settlement offers are being exchanged under the FERC administrative law judge's guidance and in participation with FERC staff. Any refunds to the applicable tariff rates would only apply to after March 26, 2020. FERC's March 20, 2020 order regarding our PDO denied our requested declaration regarding the preemption of the United and LPEA proceedings at the COPUC stating they are not currently preempted.

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

On July 13, 2020, we filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit, or 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 PDO and FERC's order granting rehearings for further consideration. Petitions for review related to both the PDO and tariff filings have been filed with the D.C. Circuit Court of Appeals by other parties. On September 18, 2020, FERC filed to hold the appeals in abeyance. On September 29, 2020, an order was filed considering the motion to hold the case in abeyance, directing the parties to file motions to govern future proceedings by January 11, 2021.

It is not possible to predict if FERC will require us to refund amounts to our customers for sales after March 26, 2020, if FERC will approve our current practices regarding use of regulatory assets are just and reasonable, or to estimate any liability associated with these matters. In addition, we cannot predict the outcome of the 206 proceedings, any requests for rehearing filed with FERC, or our petition for review or any other petitions for review filed with the D.C. Circuit Court of Appeals.

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

Exhibit Number	Description of Exhibit
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: November 12, 2020

By: /s/ Duane Highley
Duane Highley
Chief Executive Officer

Date: November 12, 2020

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