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 June 30, 2019

OR

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

For the transition period from to

Commission File No. 333-212006

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

Colorado	**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 JUNE 30, 2019

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 or operation 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)

	June 30, 2019 (unaudited)	December 31, 2018
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,954,957	$ 5,899,128
Construction work in progress	205,962	207,732
Total electric plant	6,160,919	6,106,860
Less allowances for depreciation and amortization	(2,555,488)	(2,499,376)
Net electric plant	3,605,431	3,607,484
Other plant	404,861	384,650
Less allowances for depreciation, amortization and depletion	(109,333)	(110,939)
Net other plant	295,528	273,711
Total property, plant and equipment	3,900,959	3,881,195
Other assets and investments		
Investments in other associations	162,648	161,487
Investments in and advances to coal mines	18,150	18,928
Restricted cash and investments	16,640	10,606
Intangible assets, net of accumulated amortization	—	3,662
Other noncurrent assets	9,180	9,022
Total other assets and investments	206,618	203,705
Current assets		
Cash and cash equivalents	101,641	116,858
Restricted cash and investments	154	126
Deposits and advances	40,106	29,641
Accounts receivable—Members	103,696	107,572
Other accounts receivable	14,677	22,434
Coal inventory	54,479	55,883
Materials and supplies	98,650	93,786
Total current assets	413,403	426,300
Deferred charges		
Regulatory assets	430,021	437,377
Prepayment—NRECA Retirement Security Plan	29,548	31,837
Other	42,195	46,453
Total deferred charges	501,764	515,667
Total assets	**$ 5,022,744**	**$ 5,026,867**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 1,021,358	$ 1,015,754
Accumulated other comprehensive income	184	375
Noncontrolling interest	110,841	110,169
Total equity	1,132,383	1,126,298
Long-term debt	3,077,717	3,109,301
Total capitalization	4,210,100	4,235,599
Current liabilities		
Member advances	8,372	13,988
Accounts payable	107,247	105,009
Short-term borrowings	271,303	204,145
Accrued expenses	29,599	40,285
Current asset retirement obligations	2,128	2,183
Accrued interest	29,780	32,070
Accrued property taxes	19,074	28,582
Current maturities of long-term debt	73,829	95,757
Total current liabilities	541,332	522,019
Deferred credits and other liabilities		
Regulatory liabilities	128,557	137,369
Deferred income tax liability	18,098	18,098
Asset retirement obligations	65,455	54,589
Other	49,425	50,266
Total deferred credits and other liabilities	261,535	260,322
Accumulated postretirement benefit and postemployment obligations	9,777	8,927
Total equity and liabilities	**$ 5,022,744**	**$ 5,026,867**

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Operating revenues				
Member electric sales	$ 284,658	$ 300,083	$ 583,589	589,429
Non-member electric sales	16,774	15,059	43,504	31,921
Other	13,156	12,371	27,412	24,671
	314,588	327,513	654,505	646,021
Operating expenses				
Purchased power	78,467	81,563	149,423	165,021
Fuel	51,747	48,301	136,897	100,241
Production	52,078	62,397	99,838	113,192
Transmission	40,882	41,900	80,024	81,964
General and administrative	12,096	8,797	22,909	16,525
Depreciation, amortization and depletion	38,144	39,555	76,289	79,643
Coal mining	2,553	—	6,149	—
Other	3,676	3,284	7,514	7,420
	279,643	285,797	579,043	564,006
Operating margins	**34,945**	**41,716**	**75,462**	**82,015**
Other income				
Interest	1,377	1,236	2,792	2,439
Capital credits from cooperatives	337	145	3,334	4,200
Other, net	631	939	1,912	2,143
	2,345	2,320	8,038	8,782
Interest expense, net of amounts capitalized	37,643	38,982	75,924	77,003
Income tax benefit	(77)	(151)	(154)	(302)
Net margins including noncontrolling interest	(276)	5,205	7,730	14,096
Net income attributable to noncontrolling interest	(1,109)	(827)	(2,126)	(1,624)
Net margins attributable to the Association	**$ (1,385)**	**$ 4,378**	**$ 5,604**	**$ 12,472**

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 June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Net margins including noncontrolling interest	$ (276)	$ 5,205	$ 7,730	$ 14,096
Other comprehensive income (loss):				
Reclassification of unrealized gain on securities available for sale included in net margin	—	—	—	(159)
Amortization of prior service cost (credit)	(10)	(19)	23	(39)
Unrecognized prior service cost	—	—	(214)	—
Other comprehensive income (loss)	(10)	(19)	(191)	(198)
Comprehensive income (loss) including noncontrolling interest	(286)	5,186	7,539	13,898
Net comprehensive income attributable to noncontrolling interest	(1,109)	(827)	(2,126)	(1,624)
Comprehensive income (loss) attributable to the Association	**$ (1,395)**	**$ 4,359**	**$ 5,413**	**$ 12,274**

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 June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Patronage capital equity at beginning of period	$ 1,022,743	$ 1,011,114	$ 1,015,754	$ 1,003,020
Net margins attributable to the Association	(1,385)	4,378	5,604	12,472
Patronage capital equity at end of period	**1,021,358**	**1,015,492**	**1,021,358**	**1,015,492**
Accumulated other comprehensive income (loss) at beginning of period	194	(389)	375	(210)
Reclassification adjustment for unrealized gain on securities available for sale included in net margin	—	—	—	(159)
Amortization of prior service cost (credit)	(10)	(19)	23	(39)
Unrecognized prior service cost	—	—	(214)	—
Accumulated other comprehensive income (loss) at end of period	**184**	**(408)**	**184**	**(408)**
Noncontrolling interest at beginning of period	109,732	109,234	110,169	111,295
Net comprehensive income attributable to noncontrolling interest	1,109	827	2,126	1,624
Equity distribution to noncontrolling interest	—	—	(1,454)	(2,858)
Noncontrolling interest at end of period	**110,841**	**110,061**	**110,841**	**110,061**
Total equity at end of period	**$ 1,132,383**	**$ 1,125,145**	**$ 1,132,383**	**$ 1,125,145**

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)

	Six Months Ended June 30,	
	2019	**2018**
Operating activities		
Net margins including noncontrolling interest	$ 7,730	$ 14,096
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	76,289	79,643
Amortization of intangible asset	3,662	3,662
Amortization of NRECA Retirement Security Plan prepayment	2,686	2,686
Amortization of debt issuance costs	1,171	1,777
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(448)	(1,152)
Changes in operating assets and liabilities:		
Accounts receivable	11,889	(39,567)
Coal inventory	1,404	(31,466)
Materials and supplies	(4,863)	(2,028)
Accounts payable and accrued expenses	5,155	22,481
Accrued interest	(2,290)	(1,083)
Accrued property taxes	(9,508)	(8,452)
Other	(3,688)	(14,834)
Net cash provided by operating activities	**89,189**	**25,763**
Investing activities		
Purchases of plant	(90,913)	(110,711)
Changes in deferred charges	1,538	(531)
Proceeds from other investments	65	64
Net cash used in investing activities	**(89,310)**	**(111,178)**
Financing activities		
Changes in Member advances	(9,357)	(1,528)
Payments of long-term debt	(88,919)	(69,881)
Proceeds from issuance of long-term debt	34,910	60,000
Debt issuance costs	(13)	—
Increase in short-term borrowings, net	67,157	76,633
Retirement of patronage capital	(11,101)	(4,852)
Equity distribution to noncontrolling interest	(1,454)	(2,858)
Other	(257)	(1,545)
Net cash provided by (used in) financing activities	**(9,034)**	**55,969**
Net decrease in cash, cash equivalents and restricted cash and investments	**(9,155)**	**(29,446)**
Cash, cash equivalents and restricted cash and investments – beginning	**127,590**	**150,965**
Cash, cash equivalents and restricted cash and investments – ending	**$ 118,435**	**$ 121,519**
Supplemental cash flow information:		
Cash paid for interest	$ 82,509	$ 81,075
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (655)	$ (795)

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 Six Months Ended June 30, 2019 and 2018

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, 2018 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 June 30, 2019, results of operations for the three and six months ended June 30, 2019 and 2018, and cash flows for the six months ended June 30, 2019 and 2018 are not necessarily indicative of the results that may be expected for an entire year or any other period.

Basis of Consolidation

Our consolidated financial statements include the 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. All significant intercompany balances and transactions have been eliminated 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 June 30, 2019 (dollars in thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Generating Station Units 1 and 2	24.00 %	$ 396,657	$ 243,439	$ 559
MBPP - Laramie River Station	27.13 %	430,487	297,872	59,061
Total		$ 827,144	$ 541,311	$ 59,620

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"), which has budgetary and rate-setting authority, if 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 member distribution systems ("Members") based on rates approved by our Board in accordance with our rate policy. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Members based on rates approved by our Board in accordance with our rate policy. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expense concurrent with their recovery in rates.

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

	June 30, 2019	December 31, 2018
Regulatory assets		
Deferred income tax expense (1)	$ 18,098	$ 18,098
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	84,860	86,005
Goodwill – J.M. Shafer (3)	50,569	51,994
Goodwill – Colowyo Coal (4)	37,711	38,227
Deferred debt prepayment transaction costs (5)	145,245	149,559
Deferred Holcomb expansion impairment loss (6)	93,494	93,494
Other	44	—
Total regulatory assets	430,021	437,377
Regulatory liabilities		
Interest rate swap - unrealized gain (7)	—	8,576
Interest rate swap - realized gain (8)	3,979	4,215
Deferred revenues (9)	82,006	82,006
Membership withdrawal (10)	42,572	42,572
Total regulatory liabilities	128,557	137,369
Net regulatory asset	$ 301,464	$ 300,008

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

(2) Represents deferral of the loss on acquisition related to the Springerville Generating Station Unit 3 ("Springerville Unit 3") prepaid lease expense upon acquiring a controlling interest in the Springerville Unit 3 Partnership LP ("Springerville Partnership") in 2009. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Members in rates.

(3) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Members in rates.

(4) Represents goodwill related to our acquisition of Colowyo Coal Company LP ("Colowyo Coal") in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $1.0 million annually through the 44-year period ending in 2056 and recovered from our Members in rates.

(5) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of $8.6 million annually over the 21-year period ending in 2035 and recovered from our Members in rates.

(6) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights for the expansion of the Holcomb Generating Station. The plan for the recovery from our Members in rates has not been determined by our Board. Once the plan for recovery is determined, the deferred impairment loss will be recognized in other operating expenses.

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

(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 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 Members through reduced rates when recognized in non-member electric sales revenue in future periods.
(10) Represents the deferral of the recognition of other income recorded in connection with the withdrawal of a former Member from membership in us. This deferred membership withdrawal income will be refunded to Members through reduced rates when recognized in other income in future periods.

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):

	June 30, **2019**	December 31, **2018**
Basin Electric Power Cooperative	$ 118,115	$ 118,115
National Rural Utilities Cooperative Finance Corporation - patronage capital	11,704	11,704
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,953	16,018
CoBank, ACB	10,201	9,062
Western Fuels Association, Inc.	2,376	2,392
Other	4,299	4,196
Investments in other associations	$ 162,648	$ 161,487

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during the six months ended June 30, 2019 or during 2018.

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 MBPP, which is the owner of Laramie River Generating Station. We, through our undivided interest in the jointly owned facility MBPP, advance funds to the Dry Fork Mine.

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

	June 30, **2019**	December 31, **2018**
Investment in Trapper Mine	$ 15,615	$ 15,350
Advances to Dry Fork Mine	2,535	3,578
Investments in and advances to coal mines	$ 18,150	$ 18,928

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 funds 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 funds 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):

	June 30, **2019**	December 31, **2018**
Cash and cash equivalents	$ 101,641	$ 116,858
Restricted cash and investments - current	154	126
Restricted cash and investments - noncurrent	16,640	10,606
Cash, cash equivalents and restricted cash and investments	$ 118,435	$ 127,590

Our Board Policy for Financial Goals and Capital Credits was revised in 2018 to provide that our Board will endeavor to fund an internally restricted cash account for the purpose of cash funding deferred revenues and incomes held as regulatory liabilities. In connection with such policy, our Board has internally restricted cash in the amount of $10.6 million and $4.6 million as of June 30, 2019 and December 31, 2018, respectively, which is included in restricted cash and investments - noncurrent.

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 six months ended June 30, 2019, we recognized $0.4 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):

	June 30, **2019**	December 31, **2018**
Accounts receivable - Members	$ 103,696	$ 107,572
Other accounts receivable - trade:		
Non-member electric sales	4,356	6,998
Other	9,575	6,006
Total other accounts receivable - trade	13,931	13,004
Other accounts receivable - nontrade	746	9,430
Total other accounts receivable	$ 14,677	$ 22,434
Contract liabilities (unearned revenue)	$ 7,473	$ 7,906

NOTE 7 – OTHER DEFERRED CHARGES

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

	June 30, **2019**	December 31, **2018**
Preliminary surveys and investigations	$ 21,647	$ 20,660
Advances to operating agents of jointly owned facilities	11,846	13,161
Interest rate swap	—	8,576
Operating lease right-of-use assets	5,025	—
Other	3,677	4,056
Total other deferred charges	$ 42,195	$ 46,453

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

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.

In 2016, we entered into a forward starting interest rate swap to hedge a portion of our future long-term debt interest rate exposure. The unrealized gain on this interest rate swap of $8.6 million as of December 31, 2018 was deferred in accordance with the accounting requirements related to regulated operations. See Note 2 – Accounting for Rate Regulation. This interest rate swap was terminated in June 2019 with no gain or loss being realized.

A right-of-use asset represents a lessee's right to use (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 $3.1 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture") except for one unsecured note in the aggregate amount of $30.8 million as of June 30, 2019. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a debt service ratio requirement and equity to capitalization ratio requirement.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation, as lead arranger and administrative agent, in the amount of $650 million ("2018 Revolving Credit Agreement") that expires on April 25, 2023. We had no outstanding borrowings as of June 30, 2019. As of June 30, 2019, we had $378.0 million in availability (including $228.0 million under the commercial paper back-up sublimit) under the 2018 Revolving Credit Agreement.

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

	June 30, **2019**	December 31, **2018**
Total debt	$ 3,173,653	$ 3,227,663
Less debt issuance costs	(28,617)	(29,775)
Less debt discounts	(10,025)	(10,139)
Plus debt premiums	16,535	17,309
Total debt adjusted for debt issuance costs, discounts and premiums	3,151,546	3,205,058
Less current maturities	(73,829)	(95,757)
Long-term debt	$ 3,077,717	$ 3,109,301

On December 11, 2018, we entered into a Term Loan Agreement with CoBank, ACB under which we issued our First Mortgage Obligations, Series 2018B which consist of fixed rate borrowings in the amount of $55.2 million and variable rate borrowings in the amount of $69.8 million. Upon closing, the full amount of the fixed rate borrowing and $34.9 million of the variable rate borrowings were funded. On April 4, 2019 we drew the remaining $34.9 million of funds for a combined variable rate total of $69.8 million, resulting in the Term Loan Agreement being fully funded for $125 million. $55.2 million of the total proceeds were used to refinance an existing term loan with CoBank, ACB and the remaining proceeds were used to delay additional commercial paper borrowings or to repay outstanding commercial paper.

We are exposed to certain risks in the normal course of operations in providing a reliable and affordable source of wholesale electricity to our Members. These risks include interest rate risk, which represents the risk of increased operating expenses and higher rates due to increases in interest rates related to anticipated future long-term borrowings. To manage this exposure, we may enter into an instrument, such as an interest rate swap, to hedge a portion of our future long-term debt interest rate exposure. In 2016, we entered into a forward starting interest rate swap. The swap was terminated in June 2019 without an associated debt issuance and no gain or loss was realized on our consolidated statements of operations.

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 2018 Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our 2018 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):

	June 30, 2019	December 31, 2018
Commercial paper outstanding, net of discounts	$ 271,303	$ 204,145
Weighted average interest rate	2.54 %	2.65 %

At June 30, 2019, $228.0 million of the commercial paper back-up sublimit remained available under the 2018 Revolving Credit Agreement. See Note 8 – Long-Term Debt.

NOTE 10 – ASSET RETIREMENT OBLIGATIONS

We account for current obligations associated with the future retirement of tangible long-lived assets 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 over the estimated useful life of that 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.

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 started final reclamation in June 2017.

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 are as follows (dollars in thousands):

	Six Months Ended June 30, 2019
Asset retirement obligations at beginning of period	$ 56,772
Liabilities incurred	9,900
Liabilities settled	(345)
Accretion expense	1,256
Change in cash flow estimate	—
Total asset retirement obligations at end of period	$ 67,583
Less current asset retirement obligations at end of period	(2,128)
Long-term asset retirement obligations at end of period	$ 65,455

The additional asset retirement obligation liability of $9.9 million was due to anticipated revision to the New Horizon mine reclamation plan to accommodate an alternative post mine land use, including construction of a pond, as necessary for final mine reclamation.

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.

The asset retirement obligations are determined in accordance with the accounting guidance and are different than the amount of any guarantees, or self-bonds for, reclamation obligations that are based upon state requirements.

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):

	June 30, **2019**	December 31, **2018**
Transmission easements	$ 20,687	$ 20,966
Operating lease liabilities - noncurrent	1,819	—
Contract liabilities (unearned revenue) - noncurrent	4,405	4,592
Customer deposits	2,474	2,458
Other	20,040	22,250
Total other deferred credits and other liabilities	$ 49,425	$ 50,266

In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. $31.8 million will be paid by us for these easements from 2019 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were $20.7 and $21.0 million as of June 30, 2019 and December 31, 2018, 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 June 30, 2019, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles.

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

		June 30, **2019**
Postretirement medical benefit obligation at beginning of period	$	8,556
Service cost		339
Interest cost		144
Benefit payments (net of contributions by participants)		(265)
Postretirement medical benefit obligation at end of period	$	8,774
Postemployment medical benefit obligation at end of period		371
Total postretirement and postemployment medical obligations at end of period	$	9,145

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):

		June 30, **2019**
Amounts included in accumulated other comprehensive income at beginning of period	$	375
Amortization of prior service credit into other income		(39)
Amounts included in accumulated other comprehensive income at end of period	$	336

Defined Benefit Plans

We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan, both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees currently participate in one of the following pension restoration plans: the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan. Eligibility is determined annually and is based on January 1 base salary that exceeds the limits of the defined benefit plan. As of June 30, 2019, the executive benefit restoration obligation included in accumulated postretirement benefit and postemployment obligations on our consolidated statements of financial position was $0.6 million.

NOTE 13 – REVENUE

Revenue from Contracts with Customers

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

Member electric sales

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	2018
Non-member electric sales:				
Long-term contracts	$ 10,912	$ 10,530	$ 22,594	$ 22,473
Short-term contracts	5,862	4,529	20,910	9,448
Other	13,156	12,371	27,412	24,671
Total non-member electric sales and other operating revenue	$ 29,930	$ 27,430	$ 70,916	$ 56,592

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 the following revenue streams: wheeling, transmission, supplying steam and water, leasing, and coal sales. 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 was issued). Transmission revenue is from Southwest Power Pool's scheduling of transmission across our transmission assets 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 that is required to be accounted for as an operating lease since the arrangement conveys 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 our progress of our 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. Our consolidated statements of operations included an income tax benefit of $0.2 million for the six months ended June 30, 2019 and $0.3 million for the comparable period in 2018. These income tax benefits are due to an alternative minimum tax credit refund.

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 are included in current liabilities and the long-term portion of lease liabilities are 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 power generating equipment at the Brush Generating Station and for the use of various facilities and operational assets. Under the power purchase arrangement at the Brush Generating Station, we are 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 for a 10-year term ending December 31, 2019 and whereby we provide our own natural gas for generation of electricity. We do not anticipate renewing this power purchase arrangement.

Rent expense for all short-term and long-term operating leases was $1.8 million for the three months ended June 30, 2019 and $2.0 million for the comparable period in 2018. Rent expense for all short-term and long-term operating leases was $3.6 million for the six months ended June 30, 2019 and $4.0 million for the comparable period in 2018. Rent expense is included in operating expenses on our consolidated statements of operations. As of June 30, 2019, there were no arrangements accounted for as finance leases.

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

	June 30, 2019
Operating leases	
Operating lease right-of-use assets	$ 7,768
Less: Accumulated amortization	(2,743)
Net operating lease right-of-use assets	$ 5,025
Operating lease liabilities - current	$ 3,550
Operating lease liabilities - noncurrent	1,819
Total operating lease liabilities	$ 5,369
Operating leases	
Weighted average remaining lease term (years)	3.79
Weighted average discount rate	6.36%

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

Year 1	$ 3,618
Year 2	514
Year 3	383
Year 4	274
Year 5	245
Thereafter	986
Total lease payments	$ 6,020
Less imputed interest	(651)
Total	$ 5,369

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 are 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 $4.6 and $4.2 million for the three months ended June 30, 2019 and 2018, respectively, and $8.9 and $8.8 million for the six months ended June 30, 2019 and 2018, respectively, are included in other operating revenue on our consolidated statements of operations.

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):

	As of June 30, 2019		As of December 31, 2018	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 594	$ 582	$ 818	$ 712

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $95.8 million as of June 30, 2019 and $107.2 million as of December 31, 2018.

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):

	As of June 30, 2019		As of December 31, 2018	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,173,653	$ 3,563,221	$ 3,227,663	$ 3,421,753

Interest Rate Swaps

In 2016, we entered into a forward starting interest rate swap to hedge a portion of our future long-term debt interest rate expense. See Note 8 – Long-Term Debt. This interest rate swap was determined to be a derivative instrument in accordance with ASC 815, Derivatives and Hedging, and was recorded at fair value on a recurring basis. The estimated fair value of this interest rate swap utilizes observable inputs based on market data obtained from independent sources and is therefore considered a Level 2 input (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs) and is included in other deferred charges on our consolidated statements of financial position. At December 31, 2018, the fair value of the interest rate swap was an unrealized gain of $8.6 million, which was deferred in accordance with our regulatory accounting. This interest rate swap was terminated in June 2019 with no gain or loss realized on our consolidated statements of operations.

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):

	June 30, 2019	December 31, 2018
Net electric plant	$ 785,480	$ 794,549
Noncontrolling interest	$ 110,841	$ 110,169
Long-term debt	$ 381,571	$ 416,057
Accrued interest	$ 11,050	$ 12,056

Our consolidated statements of operations include the following Springerville Partnership expenses for the three and six months ended June 30, 2019 and 2018 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Depreciation, amortization and depletion	$ 4,535	$ 4,535	$ 9,069	$ 9,069
Interest	$ 5,933	$ 7,234	$ 12,764	$ 14,536

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 supplies fuel to MBPP for the use of the Laramie River Station through its ownership in Western Fuels-Wyoming. We also receive coal supplies directly from WFA for the Escalante Generating Station in New Mexico. The pricing structure of the coal supply agreements with WFA is designed to recover the mine operating costs of the mine supplying the coal and therefore the coal sales agreements provide the financial support for the mine operations. There is not sufficient equity at risk for WFA to finance its activities without additional financial support. Therefore, WFA is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact WFA’s economic performance (acquiring and supplying fuel resources) is held by the members who are represented on the WFA board of directors whose actions require joint approval. Therefore, since there is shared power over the significant activities of WFA, we are not the primary beneficiary of WFA and the entity is not consolidated. Our investment in WFA, accounted for using the cost method, was $2.4 million at June 30, 2019 and December 31, 2018 and is included in investments in other associations.

Western Fuels – Wyoming (“WFW”): WFW, the owner and operator of the Dry Fork Mine in Gillette, WY, 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 June 30, 2019 and December 31, 2018 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 cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of Trapper Mining and the entity is not consolidated. We record our investment in Trapper Mining using the equity method. Our membership interest in Trapper Mining was $15.6 million at June 30, 2019 and $15.4 million at December 31, 2018.

NOTE 18 – LEGAL

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

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 has claimed damages caused by the alleged breach of approximately $7.3 million. The utility is seeking arbitration to resolve the dispute, but no arbitration proceeding has commenced. It is not possible to predict whether we will incur any liability in connection with this matter.

NOTE 19 – SUBSEQUENT EVENTS

In July 2019, we announced that Nucla Generation Station, a 100-MW coal-fired generating facility in Western Colorado, is expected to be retired in early 2020 following the exhaustion of its on-site fuel supply. Nucla Generation Station, which has been in a ready-to-run status, was to be retired by the end of 2022 as required by Colorado's State Implementation Plan. As a result of the early retirement, we expect to recognize an impairment charge of approximately $34.2 million in the third quarter of 2019. The impairment charge will be immediately deferred as a regulatory asset. This cost will be amortized to other operating expenses through the period ending in 2022 and recovered from our Members in rates. To support the community through the transition, we plan to provide $0.5 million in community support spread across five years.

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 are organized for the purpose of providing electricity to our 43 member distribution systems, or Members, that serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our generated electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. Our Members provide retail electric service to suburban and rural residences, farms and ranches, cities, towns and communities, as well as large and small businesses and industries.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generation and transmission facilities, long term purchase contracts and short term energy purchases. We own, lease, have undivided percentage interests in, 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 4,519 megawatts, or MWs, of which approximately 1,059 MWs comes from renewables. In 2018, we estimate that nearly a third of the energy delivered by us and our Members to our Members' customers came from non-carbon emitting resources. In December 2018, we executed a 100 MW solar-based power purchase agreement for the Spanish Peaks Solar Project that is expected to achieve commercial operation in 2023. In February 2019, we executed a 104 MW wind-based power purchase agreement for the Crossing Trails Wind Farm that is expected to achieve commercial operation in 2020. Upon commercial operation of these two renewable generating facilities, our renewable generation portfolio is expected to increase to 1,263 MWs. In June 2019, we issued our sixth request for proposal for renewable energy resources. The 2019 request for proposal seeks projects of 10 MWs to 200 MWs with terms of 10 to 25 years.

We sold 8.7 million megawatt hours, or MWhs, for the six months ended June 30, 2019, of which 89.7 percent was to Members. Total revenue from electric sales was $627.1 million for the six months ended June 30, 2019, of which 93.1 percent was from Member sales. Our results for the six months ended June 30, 2019 were primarily impacted by milder temperatures and a more precipitous than average spring in many of our Members' service territories.

- Non-member electric sales increased by $11.6 million, or 36.3 percent, primarily due to increased short-term market sales and higher market pricing.
- Fuel expense increased $36.6 million, or 36.6 percent, primarily due to greater generation from our generating facilities during the period.
- Purchased power expense decreased $15.6 million, or 9.4 percent, primarily due to increased availability of Craig Generating Station Unit 3 and decreased demand for market purchases of power.

Our Bylaws and Wholesale Electric Service Contracts

Pursuant to our Bylaws, each Member is required to purchase from us the electric power and energy provided in the wholesale electric service contract with such Member. Our wholesale electric service contracts with our Members extending through 2050 for 42 Members (which constitute approximately 96.6 percent of our revenue from Member sales for the six months ended June 30, 2019) and extending through 2040 for the remaining Member (Delta-Montrose Electric Association, or DMEA) are substantially similar. These contracts are subject to automatic extension thereafter until either party provides at least a two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Member and obligates the Member to purchase and receive, at least 95 percent of its electric power requirements from us. Each Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Member. As of June 30, 2019, 21 Members have enrolled in this program with capacity totaling approximately 135 MWs of which 113 MWs are in operation.

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board of Directors, or Board, may prescribe; provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. From time to time, a Member may request equitable terms and conditions as our Board may prescribe for withdrawal or we may provide for informational purposes to all or a portion of our Members equitable terms and conditions for withdrawal. In addition, from time to time, we may be in discussions with a Member regarding the equitable terms and conditions for withdrawal and their request for withdrawal, including granting a Member permission to explore options for potential alternative supplies of power. However, any such permission is not considered authorization to withdraw and does not change the Member's requirements and obligation to comply with such equitable terms and conditions as our Board may prescribe.

DMEA requested an exit cost calculation from us and we provided to DMEA a calculation of potential buyout terms. DMEA disputed the buyout terms provided to DMEA by us and, in December 2018, DMEA filed a formal complaint with the Colorado Public Utilities Commission, or COPUC, alleging the COPUC has jurisdiction over the equitable terms and conditions as our Board may prescribe for withdrawal. In July 2019, we reached a settlement of all litigation with DMEA that provides for their withdrawal from us as permitted by our Bylaws, the transfer of certain transmission assets to DMEA, and the payment to us of a withdrawal payment. The amount of the withdrawal payment was the product of the negotiated settlement with DMEA and is unique to DMEA because of the amounts associated with the transmission assets being transferred and patronage capital, and the date of withdrawal of DMEA from us. The specific terms of the settlement will be set forth in a withdrawal agreement and the parties are to cooperate to complete DMEA's withdrawal effective May 1, 2020. The parties also filed a stipulation to dismiss DMEA's formal complaint with the COPUC. See "LEGAL PROCEEDINGS."

Responsible Energy Plan

In July 2019, we announced that we are pursuing a Responsible Energy Plan to transition to a cleaner generation portfolio while ensuring reliability, increasing Member flexibility and with a goal to lower wholesale rates to our Members. Our Responsible Energy Plan will set goals and pathways to:

- comply with aggressive carbon reduction, renewable energy resource planning requirements
- ensure the reliability and affordability of our wholesale power system, and
- strive to lower wholesale rates to our Members while maintaining our strong financial position.

A key part of our approach is an engagement with former Colorado Governor Bill Ritter and the Center for the New Energy Economy at the Colorado State University to facilitate a collaborative stakeholder process for us that will contribute to and help define the Responsible Energy Plan. Our Members, through a contract committee, consisting of a representative from each Member, are currently considering greater contract flexibility for Members, including partial requirements contracts that would allow more local renewable energy projects. As part of the Responsible Energy Plan, we plan to address key issues including developing Western regional electricity markets, assisting impacted energy-producing communities, continuing and developing new tax incentives, addressing permitting for transmission line and generating facilities, and reconsidering the value of hydropower to ensure the Responsible Energy Plan's success. In July, we announced that Nucla Generation Station, a 100-MW coal-fired generating facility in Western Colorado, is expected to be retired in early 2020 following the exhaustion of its on-site fuel supply. Nucla Generation Station, which has been in a ready-to-run status, was to be retired by the end of 2022 as required by Colorado's State Implementation Plan. To support the community through the transition, we plan to provide $0.5 million in community support spread across five years.

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. Except for the accounting policies for leases that were updated as a result of adopting the new lease standard on January 1, 2019, 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, 2018.

Factors Affecting Results

Master Indenture

As of June 30, 2019, we had approximately $2.8 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 (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 Members on the basis of revenue from electricity purchases from us. Net losses, should they occur, are not allocated to our Members but are offset by future margins.

Our Board Policy for Financial Goals and Capital Credits, approved and subject to change by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Members. On a periodic basis, our Board will determine whether to retire any patronage capital, and in what amounts, to our Members. To date, we have retired approximately $355.5 million of patronage capital to our Members.

Pursuant to our Board Policy for Financial Goals and Capital Credits, we set rates to achieve a DSR and ECR in excess of the requirements under our Master Indenture in order to mitigate the risk of potential negative variances between budgeted margins and actual margins. This policy was revised in 2018 to establish a goal of our Board, which has budgetary and rate-setting authority, to either defer revenues and incomes as a regulatory liability or recognize previously deferred revenues and incomes in an amount that will result in a DSR equal to a DSR goal for the applicable year as set forth in the policy. As allowed by our Bylaws, the deferral or recognition of previously deferred revenues and income is for the purpose of stabilizing margins and limiting rate increases from year to year. In association with the above change, our Board Policy for Financial Goals and Capital Credits was also revised to provide that our Board will endeavor to fund an internally restricted cash account for the purpose of cash funding deferred revenues and incomes held as regulatory liabilities. The amount of cash our Board may internally restrict each year is not based upon the amount of revenue and income deferred. In connection with such policy, our Board has internally restricted cash in the amount of $6.0 million during the six months ended June 30, 2019 for a total of $10.6 million as of June 30, 2019. Our Board may, at any time and for any reason, unrestrict any internally restricted cash.

Rates and Regulation

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Revenues from electric power sales to our Members are primarily from our Class A wholesale rate schedule. In 2018 and 2019, our Class A rate schedule (A-40) for electric power sales to our Members consist of three billing components: an energy rate and two demand rates. Member rates for energy and demand are set by our Board, consistent with the provision of reliable cost-based supply of electricity over the long term to our Members. The energy rate is billed based upon a price per kilowatt hour of physical electricity delivered to our Members without incorporating an on-peak and off-peak period. The two demand rates (a generation demand and a transmission/delivery demand) are billed on the Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays.

Although rates established by our Board are generally not currently subject to regulation by federal, state or other governmental agencies, we are currently required to submit our rate schedules to the New Mexico Public Regulation Commission, or NMPRC. The NMPRC currently only has regulatory authority over rates in New Mexico in the event three or more of our New Mexico Members file a request for such a review and such review is found to be qualified by the NMPRC. In 2012, the NMPRC suspended our Class A rate schedule (A-37) from going into effect in New Mexico, resulting in New Mexico Members paying different rates than Members in other states. See "Item 3 – LEGAL PROCEEDINGS" in our annual report on Form 10-K for the year ended December 31, 2018. In 2013, the COPUC also asserted rate jurisdiction regarding a rate complaint filed with the COPUC from three of our Colorado Members. In 2015, we and our three Colorado Members filed a joint motion with the COPUC to withdraw the complaint and dismiss the proceeding.

At our July 2019 Board meeting, our Board took action that will place us under wholesale rate regulation by the Federal Energy Regulatory Commission, or FERC. We are currently exempt from FERC wholesale rate regulation pursuant to the Federal Power Act because we are wholly-owned by entities that are themselves not subject to rate regulation by FERC. Each of our Members are not subject to rate regulation by FERC because each Member is either a public power district or an electric cooperative that does not currently sell more than 4 million MWhs annually. In order to no longer be exempt pursuant to the Federal Power Act, our Board, in accordance with our Bylaws, established a non-utility membership class and authorized entering into membership agreements with non-utility members. The non-utility membership class, as set forth in the membership agreements, will have a right to vote in an annual membership meeting, will have rights to patronage capital, and will have rights to liquidation proceeds, but will have no representation on our Board. Upon the admission of one or more members that is not an electric cooperative or a governmental entity, we will cease to be wholly-owned by such entities and such admission will eliminate our exemption from FERC regulation.

On July 23, 2019, we filed with FERC our initial tariff, including our stated rate cost of service filing, market based rate authorization, and transmission Open Access Transmission Tariff. Our FERC tariff filing included our current Class A rate schedule (A-40) for electric power sales to our Members as the wholesale rates payable by our Members. Upon acceptance by FERC of our rate filing and the effectiveness of a membership agreement with a non-utility member, we will become subject to general "public utility" regulation by FERC, including our rates for transmission service provided in the Western Interconnection. FERC's regulation of our wholesale rates to our Members would eliminate the possibility of inconsistent rate jurisdiction by one or more states.

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

Weather has a significant effect on the usage of electricity by impacting both the electricity used per hour and the total peak demand for electricity. Consequently, weather has a significant impact on our revenues and expenses. Relatively higher summer or lower winter temperatures tend to increase the usage of electricity for heating, air conditioning and irrigation. Mild weather generally reduces the usage of electricity because heating, air conditioning and irrigation systems are operated less frequently. The amount of precipitation during the growing season (generally May through September) also impacts irrigation use. Other factors affecting our Members' usage of electricity include:

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

Three months ended June 30, 2019 compared to three months ended June 30, 2018

Operating Revenues

Our operating revenues are primarily derived from electric power sales to our Members and non-member purchasers. The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the three months ended June 30, 2019 and 2018 (dollars in thousands):

	Three Months Ended June 30,		Period-to-period Change	
	2019	**2018**	**Amount**	**Percent**
Operating revenues				
Member electric sales	$ 284,658	$ 300,083	$ (15,425)	(5.1)%
Non-member electric sales	16,774	15,059	1,715	11.4%
Other	13,156	12,371	785	6.3%
Total operating revenues	$ 314,588	$ 327,513	$ (12,925)	(3.9)%
Energy sales to (in MWh):				
Member electric sales	3,734,677	3,905,100	(170,423)	(4.4)%
Non-member electric sales	335,592	273,635	61,957	22.6%
	4,070,269	4,178,735	(108,466)	(2.6)%

- Member electric sales decreased primarily due to lower Member energy needs because of milder temperatures and above average precipitation in many Members' service territories during the three months ended June 30, 2019 compared to the same period in 2018.

Operating Expenses

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

The following is a summary of the components of our operating expenses for the three months ended June 30, 2019 and 2018 (dollars in thousands):

	Three Months Ended June 30,		Period-to-period Change	
	2019	2018	Amount	Percent
Operating expenses				
Purchased power	$ 78,467	$ 81,563	$ (3,096)	(3.8)%
Fuel	51,747	48,301	3,446	7.1%
Production	52,078	62,397	(10,319)	(16.5)%
Transmission	40,882	41,900	(1,018)	(2.4)%
General and administrative	12,096	8,797	3,299	37.5%
Depreciation, amortization and depletion	38,144	39,555	(1,411)	(3.6)%
Coal mining	2,553	—	2,553	100.0%
Other	3,676	3,284	392	11.9%
Total operating expenses	$ 279,643	$ 285,797	$ (6,154)	(2.2)%

- Production expense decreased primarily due to decreased maintenance costs during the three months ended June 30, 2019 compared to the same period in 2018. Craig Generating Station Unit 3 experienced an unplanned maintenance outage that began in December 2017 and was brought back online in June 2018 which resulted in increased maintenance costs during the three months ended June 30, 2018 compared to the same period in 2019.
- Coal mining expense increased due to the costs to provide coal from the Colowyo Mine to third parties during the three months ended June 30, 2019. There were no third party sales of coal from the Colowyo Mine during the same period in 2018.

Six months ended June 30, 2019 compared to six months ended June 30, 2018

Operating Revenues

The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the six months ended June 30, 2019 and 2018 (dollars in thousands):

	Six Months Ended June 30,		Period-to-period Change	
	2019	2018	Amount	Percent
Operating revenues				
Member electric sales	$ 583,589	$ 589,429	$ (5,840)	(1.0)%
Non-member electric sales	43,504	31,921	11,583	36.3%
Other	27,412	24,671	2,741	11.1%
Total operating revenues	$ 654,505	$ 646,021	$ 8,484	1.3%
Energy sales to (in MWh):				
Member electric sales	7,768,198	7,818,134	(49,936)	(0.6)%
Non-member electric sales	894,660	626,814	267,846	42.7%
	8,662,858	8,444,948	217,910	2.6%

- Non-member electric sales increased primarily due to increased short-term market sales and more favorable pricing. Short-term market sales increased 202,851 MWhs, or 146.8 percent, to 341,005 MWhs for the six months ended June 30, 2019 compared to 138,154 MWhs for the same period in 2018. The average short-term market rate increased 24.2 percent for the six months ended June 30, 2019 compared to the same period in 2018.

Operating Expenses

The following is a summary of the components of our operating expenses for the six months ended June 30, 2019 and 2018 (dollars in thousands):

	Six Months Ended June 30,		Period-to-period Change	
	2019	**2018**	**Amount**	**Percent**
Operating expenses				
Purchased power	$ 149,423	$ 165,021	$ (15,598)	(9.5)%
Fuel	136,897	100,241	36,656	36.6%
Production	99,838	113,192	(13,354)	(11.8)%
Transmission	80,024	81,964	(1,940)	(2.4)%
General and administrative	22,909	16,525	6,384	38.6%
Depreciation, amortization and depletion	76,289	79,643	(3,354)	(4.2)%
Coal mining	6,149	—	6,149	100.0%
Other	7,514	7,420	94	1.3%
Total operating expenses	$ 579,043	$ 564,006	$ 15,037	2.7%

- Purchased power expense decreased primarily due to energy demands being met by increased generation from our generating facilities. Purchased power decreased (in MWhs) 17.5 percent for the six months ended June 30, 2019 compared to the same period in 2018. This decrease was partially offset by a 9.5 percent increase in the average price of purchased power during the six months ended June 30, 2019 compared to the same period in 2018.
- Fuel expense increased due to greater generation from our generating facilities during the period. Net generation increased (in MWhs) 19.9 percent for the six months ended June 30, 2019 compared to the same period in 2018. The increase in generation is primarily attributable to the availability of Craig Generating Station Unit 3 during the six months ended June 30, 2019. Also included in fuel expense is an additional asset retirement 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 decreased maintenance costs during the period. Craig Generating Station Unit 3 experienced an unplanned maintenance outage that began in December 2017 and was brought back online in June 2018 which resulted in increased maintenance costs during the six months ended June 30, 2018 compared to the same period in the current year.
- Coal mining expense increased due to the costs to provide coal from the Colowyo Mine to third parties during the six months ended June 30, 2019. There were no third party sales of coal from the Colowyo Mine during the same period in 2018.

Financial condition as of June 30, 2019 compared to December 31, 2018

The principal changes in our financial condition from December 31, 2018 to June 30, 2019 were due to increases and decreases in the following:

Assets

- Deposits and advances increased $10.5 million, or 35.3 percent, to $40.1 million as of June 30, 2019 compared to $29.6 million as of December 31, 2018. The increase was primarily due to prepayments of annual insurance, memberships and licenses. These prepayments are being amortized to expense over the term of the related insurance, membership or license period.

Liabilities

- Short-term borrowings increased $67.2 million, or 32.9 percent, to $271.3 million as of June 30, 2019 compared to $204.1 million as of December 31, 2018. Short-term borrowings consist of our commercial paper program that provides an additional financing source for our short-term liquidity needs. The increase was due to additional commercial paper issued between January 1, 2019 and June 30, 2019 to fund capital expenditures and working capital requirements.
- Accrued property taxes decreased $9.5 million, or 33.3 percent, to $19.1 million as of June 30, 2019 compared to $28.6 million as of December 31, 2018. The decrease was primarily due to $28.5 million of property tax payments during 2019 (of which $17.3 million were paid during the second quarter of 2019) partially offset by accruals for property taxes due in future periods.
- Current maturities of long-term debt decreased $22.0 million, or 22.9 percent, to $73.8 million as of June 30, 2019 compared to $95.8 million as of December 31, 2018. The decrease was primarily due to a decrease of $27.1 million for the First Mortgage Obligations, Series 2009 principal payment that is due during the second quarter of 2020. This decrease was partially offset by an increase of $3.4 million for the Springerville certificates principal payment that is due during the first quarter of 2020.
- Regulatory liabilities decreased $8.8 million, or 6.4 percent, to $128.6 million as of June 30, 2019 compared to $137.4 million as of December 31, 2018. The decrease was primarily due the June 2019 settlement of an interest rate swap. This interest rate swap was terminated with no associated debt issuance and no gain or loss was realized on our consolidated statements of operations.
- Asset retirement obligations increased $10.9 million, or 19.9 percent, to $65.5 million as of June 30, 2019 compared to $54.6 million as of December 31, 2018. The increase was primarily due to an increased asset retirement obligation of $9.9 million for 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.

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 June 30, 2019, we had $101.6 million in cash and cash equivalents. Our committed credit arrangement as of June 30, 2019 is as follows (dollars in thousands):

	Authorized Amount	Available June 30, 2019
2018 Revolving Credit Agreement	$ 650,000 (1)	$ 378,000 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.
(2) The portion of this facility that was unavailable at June 30, 2019 was $272 million which was dedicated to support outstanding commercial paper.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation, as lead arranger and administrative agent, in the amount of $650 million, or the 2018 Revolving Credit Agreement. The 2018 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 $228 million of the commercial paper back-up sublimit remained available as of June 30, 2019. As of June 30, 2019, we had $378 million of availability under the 2018 Revolving Credit Agreement.

The 2018 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 2018 Revolving Credit Agreement bear interest either at an adjusted LIBOR rate or an alternate base rate, at our option. The adjusted LIBOR rate is the LIBOR rate for the term of the advance plus a margin (currently 1.00%) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00%, (b) the prime rate, and (c) the one-month LIBOR rate plus 1.00% and plus a margin (currently 0%) based on our credit ratings. We had no outstanding borrowings at June 30, 2019.

The 2018 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 2018 Revolving Credit Agreement, which was $500 million at June 30, 2019, thereby providing 100 percent dedicated support for any commercial paper outstanding. We had $272 million of commercial paper outstanding (prior to netting discounts) at June 30, 2019.

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

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, and the 2018 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.

Six months ended June 30, 2019 compared to six months ended June 30, 2018

Operating activities. Net cash provided by operating activities was $89.2 million for the six months ended June 30, 2019 compared to $25.8 million for the same period in 2018, an increase of $63.4 million. The increase in cash provided by operating activities was primarily impacted by a decrease in coal inventory (due to lower coal production tons at the Colowyo Mine), a decrease in other accounts receivable related to the settlement of insurance recoveries and an increase in cash collected from Member accounts receivable.

Investing activities. Net cash used in investing activities was $89.3 million for the six months ended June 30, 2019 compared to $111.2 million for the same period in 2018, a decrease of $21.9 million. The decrease was primarily due to lower capital expenditures in 2019 compared to the same period in 2018 for the development of the Collom mining pit at the Colowyo mine.

Financing activities. Net cash used in financing activities was $9.0 million for the six months ended June 30, 2019 compared to net cash provided by financing activities of $56.0 million for the same period in 2018, a decrease in cash provided by financing activities of $65.0 million. The decrease was primarily due to lower proceeds from issuance of long-term debt of $25.1 million, higher principal payments of long-term debt of $19.0 million (primarily for the Springerville certificates), a decrease in short-term borrowings of $9.5 million and higher patronage capital retirements to our Members of $6.2 million.

Capital Expenditures

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility costs, market factors and other items affecting our forecasts.

Our actual capital expenditures depend on a variety of factors, including 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 and development of the Collom mining pit at the Colowyo Mine.

Contractual Commitments

Indebtedness. As of June 30, 2019, we had $3.5 billion in outstanding obligations, including approximately $2.8 billion of debt outstanding secured on a parity basis under our Master Indenture, $272.0 million in short-term borrowings, one unsecured loan agreement totaling $30.8 million and the Springerville certificates totaling $371.2 million (which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease). Our debt secured by the lien of our Master Indenture includes notes payable to National Rural Utilities Cooperative Finance Corporation and CoBank, ACB (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 2018 Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under the Master Indenture.

Operating Lease Obligations. We have a 10-year power purchase agreement with AltaGas Brush Energy, Inc. to toll natural gas at the Brush Generating Station for 70 MWs, which ends on December 31, 2019. We account for this power purchase agreement as an operating lease because it conveys to us the right to use power generating equipment for a stated period of time.

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 2019 and 2034. 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.

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.

New Mexico Renewable Portfolio Standards and Colorado Greenhouse Gas Regulation

As a result of the November 2018 elections, the House of Representatives, Senate, and Governor in both Colorado and New Mexico are controlled by the same political party. The newly elected Governors in Colorado and New Mexico ran on platforms to increase renewable energy in their respective states. The New Mexico Legislature in 2019 passed Senate Bill 489, the Energy Transition Act, which was signed into law by the New Mexico Governor on March 22, 2019. The legislation amends the existing renewable energy standards, or RPS, that requires our New Mexico Members to obtain a percentage of their energy requirements from renewable sources. The legislation adds requirements for our New Mexico Members to obtain 40 percent renewable energy by 2025 and 50 percent renewable energy by 2030, and adds a target of achieving a zero carbon resource standard by 2050, with at least 80 percent renewable energy. The legislation includes regulatory relief for the 2050 target, if implementing the provisions of the bill are not technically feasible, hampers reliability or increases cost of electricity to unaffordable levels.

The Colorado General Assembly has chosen to pursue carbon reductions to meet the Governor's goal, rather than an increased RPS. The Colorado General Assembly in 2019 passed House Bill 19-1261, Climate Action Plan to Reduce

Pollution, which was signed by the Colorado Governor on May 30, 2019. The legislation requires that the Air Quality Control Commission develop rules to reduce statewide greenhouse gas emissions 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, relative to 2005 emissions.

The New Mexico and Colorado legislation is expected to have a material impact on our operations and our future generation portfolio; however until the final rules are enacted that implement the respective legislation, it is not yet possible to estimate the impacts on our operations or future generation portfolio. The impacts could include modifications to the design or operation of existing facilities, increases in our operating expenses and increases in our recovery of stranded costs, investments in new generation and transmission, and decreases in operations or closure of our fossil fuel generating facilities prior to their current depreciable lives.

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 CDPHE, in opposition to CDPHE's issuance of an air permit for construction and operation of the Collom pit at the Colowyo Mine. We and Colowyo Coal Company LP on August 23, 2018 filed an unopposed motion to intervene and answer to the complaint. The CDPHE on September 4, 2018 filed an answer and defenses to the complaint. On February 14, 2019, the court issued a stay of the case proceedings until May 1, 2019, while CDPHE processes a permit revision. As the permit revision was still pending on April 30, 2019, we filed a Motion for Stay Extension. On May 21, 2019, the Center for Biological Diversity and Sierra Club filed an Opposition to Motion for Stay Extension. On May 28, 2019, the court granted our motion to extend the stay until October 29, 2019. The court order requires parties to file a Joint Status Report by October 8, 2019.

Affordable Clean Energy Rule

On July 8, 2019, the Environmental Protection Agency, or EPA, published the final Affordable Clean Energy rule, or ACE Rule, to repeal and replace the Clean Power Plan, or CPP. Implementation of the CPP has been stayed by the United States Supreme Court since 2016. The ACE Rule requires states to develop unit-specific carbon dioxide emission rate standards for existing coal-fired units based on heat-rate efficiency improvements. Combustion turbines, including natural gas combined cycles, are not included as affected sources in the ACE Rule. The ultimate impact of the ACE Rule, including the repeal and replacement of the CPP, to us will depend on state implementation plan requirements and the outcome of any associated legal challenges and cannot be determined at this time. It is too early to know how each state in which we operate will administer the ACE Rule. If a state implements a very strict interpretation of the rule, it may have a material impact on our operations.

For further discussion regarding potential effects on our business from environmental regulations, see "Item 1 – BUSINESS — ENVIRONMENTAL REGULATION" and "Item 1A — RISK FACTORS" in our annual report on Form 10-K for the year ended December 31, 2018.

Other Legislative Changes Impacting Us

The Colorado General Assembly in 2019 passed legislation that revises processes undertaken by the COPUC. Senate Bill 19-236, Sunset Public Utilities Commission, which was signed by the Colorado Governor on May 30, 2019, continues the COPUC for seven years. Among other provisions, the bill requires us to file and obtain COPUC approval for integrated or electric resource plans and directs the COPUC to require electric public utilities to consider the cost of carbon dioxide emissions in certain proceedings. The bill could have a material impact on our operations and our future generation portfolio; however, until the final rules are enacted that implement the bill, it is not yet possible to estimate the impacts on our operations or future generation portfolio.

Rating Triggers

Our current senior secured ratings are "A3 (stable outlook)" by Moody's Investors Services, or Moody's, "A (stable 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-1" by S&P, and "F1" by Fitch.

Our 2018 Revolving Credit Agreement includes a pricing grid related to the LIBOR spread, commitment fee and letter of credit fees due under the facility. A downgrade of our senior secured ratings could result in an increase in each of these pricing components. We do not believe that any such increase would be significant or have a material adverse effect on our financial condition or our future results of operations.

We currently have contracts that require adequate assurance of performance. These include natural gas supply contracts, coal purchase contracts, and financial risk management contracts. Some of the contracts are directly tied to 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, 2018.

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.

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, 2018.

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. DMEA, which constituted approximately 3.4 percent of our revenue from Member sales for the six months ended June 30, 2019, requested an exit cost calculation from us and we provided to DMEA a calculation of potential terms for withdrawal. On December 6, 2018, DMEA filed a formal complaint with the COPUC alleging the COPUC has jurisdiction over the equitable terms and conditions as our Board may prescribe for withdrawal and that the calculation of the potential buyout terms provided to DMEA was unjust, unreasonable, and discriminatory. On January 15, 2019, we filed a motion to dismiss with the COPUC because the COPUC does not have jurisdiction over the complaint. On

February 19, 2019, the COPUC issued a written interim decision setting the matter for a 5-day evidentiary hearing beginning on June 17, 2019. On April 1, 2019, the COPUC issued a written interim decision denying our motion to dismiss. On March 15, 2019, DMEA filed its direct testimony and we filed our answer testimony on April 29, 2019. On May 14, 2019, DMEA requested a 30-day extension to file rebuttal testimony and a continuance of the hearing beginning on June 17, 2019. On May 24, 2019, the COPUC entered an interim decision granting DMEA's motion for extension, vacating the procedural schedule, and ordering the parties to submit a revised procedural schedule, and extending the rebuttal testimony deadline to June 28, 2019. On June 6, 2019, the COPUC scheduled a 5-day hearing to commence on August 12, 2019. On July 19, 2019, we signed a settlement agreement with DMEA that provides for their withdrawal from us as permitted by our Bylaws, the transfer of certain transmission assets to DMEA, and the payment to us of a withdrawal payment. The amount of the withdrawal payment was the product of the negotiated settlement with DMEA and is unique to DMEA because of the amounts associated with the transmission assets being transferred and patronage capital, and the date of withdrawal of DMEA from us. The specific terms of the settlement will be set forth in a withdrawal agreement and the parties are to cooperate to complete DMEA's withdrawal effective May 1, 2020. On July 19, 2019, the parties also filed a stipulation to dismiss DMEA's formal complaint with COPUC.

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: August 9, 2019

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

Date: August 9, 2019

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