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, 2017

OR

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

For the transition period from to

Commission File No. 333-212006

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

Colorado	**84-0464189**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
1100 West 116th Avenue **Westminster, Colorado**	**80234**
(Address of principal executive offices)	(Zip Code)

(303) 452-6111
(Registrant's telephone number, including area code)

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). **Yes** ☒ **No** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one): **Large accelerated filer** ☐ **Accelerated filer** ☐ **Non-accelerated filer** ☒ (Do not check if a smaller reporting company) **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** ☒

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

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
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FOR THE QUARTER ENDED JUNE 30, 2017

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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," "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, 2017 (unaudited)	December 31, 2016
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,761,091	$ 5,682,613
Construction work in progress	209,024	212,081
Total electric plant	5,970,115	5,894,694
Less allowances for depreciation and amortization	(2,425,069)	(2,361,555)
Net electric plant	3,545,046	3,533,139
Other plant	247,113	234,457
Less allowances for depreciation, amortization and depletion	(100,392)	(89,809)
Net other plant	146,721	144,648
Total property, plant and equipment	3,691,767	3,677,787
Other assets and investments		
Investments in other associations	140,413	139,350
Investments in and advances to coal mines	18,286	18,176
Restricted cash and investments	1,000	1,000
Intangible assets, net of accumulated amortization	14,648	18,310
Other noncurrent assets	11,828	11,542
Total other assets and investments	186,175	188,378
Current assets		
Cash and cash equivalents	139,431	165,893
Restricted cash and investments	1,075	997
Deposits and advances	40,728	25,141
Accounts receivable—Members	114,700	97,925
Other accounts receivable	17,158	24,837
Coal inventory	55,896	63,945
Materials and supplies	86,392	87,768
Total current assets	455,380	466,506
Deferred charges		
Regulatory assets	478,472	395,615
Prepayment—NRECA Retirement Security Plan	40,491	43,627
Other	46,754	139,378
Total deferred charges	565,717	578,620
Total assets	**$ 4,899,039**	**$ 4,911,291**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 989,681	$ 961,364
Accumulated other comprehensive income (loss)	(279)	(286)
Noncontrolling interest	109,820	109,147
Total equity	1,099,222	1,070,225
Long-term debt	3,069,987	3,139,705
Total capitalization	4,169,209	4,209,930
Current liabilities		
Member advances	6,731	11,363
Accounts payable	108,955	105,511
Short-term borrowings	240,206	119,901
Accrued expenses	28,357	32,719
Accrued interest	32,437	34,166
Accrued property taxes	16,987	27,584
Current maturities of long-term debt	77,337	107,903
Total current liabilities	511,010	439,147
Deferred credits and other liabilities		
Regulatory liabilities	72,729	95,512
Deferred income tax liability	30,517	30,517
Intangible liabilities	1,765	3,263
Asset retirement obligations	55,980	58,583
Other	49,487	66,164
Total deferred credits and other liabilities	210,478	254,039
Accumulated postretirement benefit and postemployment obligations	8,342	8,175
Total equity and liabilities	**$ 4,899,039**	**$ 4,911,291**

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,	
	2017	**2016**	**2017**	**2016**
Operating revenues				
Member electric sales	$ 292,259	$ 275,517	$ 574,674	$ 547,286
Non-member electric sales	25,313	25,054	60,471	55,176
Other	21,329	20,051	42,185	41,622
	338,901	320,622	677,330	644,084
Operating expenses				
Purchased power	82,356	76,558	158,775	147,593
Fuel	58,508	51,560	119,321	112,550
Production	61,088	57,016	110,649	107,998
Transmission	40,486	39,132	74,286	75,592
General and administrative	4,841	6,392	12,021	11,502
Depreciation, amortization and depletion	41,090	41,873	87,762	80,776
Coal mining	9,584	7,398	17,760	15,671
Other	3,978	3,690	8,768	9,020
	301,931	283,619	589,342	560,702
Operating margins	**36,970**	**37,003**	**87,988**	**83,382**
Other income				
Interest	1,135	1,059	2,220	2,133
Capital credits from cooperatives	151	184	4,397	4,695
Membership withdrawal	2,500	—	5,000	—
Other	409	694	1,429	1,735
	4,195	1,937	13,046	8,563
Interest expense, net of amounts capitalized	36,299	35,924	72,648	71,344
Income tax expense (benefit)	(302)	350	(604)	350
Net margins including noncontrolling interest	5,168	2,666	28,990	20,251
Net income attributable to noncontrolling interest	(377)	(129)	(673)	(181)
Net margins attributable to the Association	**$ 4,791**	**$ 2,537**	**$ 28,317**	**$ 20,070**

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,	
	2017	**2016**	**2017**	**2016**
Net margins including noncontrolling interest	$ 5,168	$ 2,666	$ 28,990	$ 20,251
Other comprehensive income (loss):				
Unrealized gain (loss) on securities available for sale	22	21	46	(1)
Amortization of actuarial gain on postretirement benefit obligation included in net income	(19)	(23)	(39)	(45)
Income tax expense related to components of other comprehensive income (loss)	—	—	—	—
Other comprehensive income (loss)	3	(2)	7	(46)
Comprehensive income including noncontrolling interest	5,171	2,664	28,997	20,205
Net comprehensive income attributable to noncontrolling interest	(377)	(129)	(673)	(181)
Comprehensive income attributable to the Association	**$ 4,794**	**$ 2,535**	**$ 28,324**	**$ 20,024**

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)

	Six Months Ended June 30,	
	2017	**2016**
Patronage capital equity at beginning of period	$ 961,364	$ 952,082
Net margins attributable to the Association	28,317	20,070
Retirement of patronage capital	—	(12,466)
Patronage capital equity at end of period	**989,681**	**959,686**
Accumulated other comprehensive income (loss) at beginning of period	(286)	589
Unrealized gain (loss) on securities available for sale	46	(1)
Amortization of actuarial gain on postretirement benefit obligation included in net income	(39)	(45)
Accumulated other comprehensive income (loss) at end of period	**(279)**	**543**
Noncontrolling interest at beginning of period	109,147	108,757
Net income attributable to noncontrolling interest	673	181
Equity distribution to noncontrolling interest	—	(59)
Noncontrolling interest at end of period	**109,820**	**108,879**
Total equity at end of period	**$ 1,099,222**	**$ 1,069,108**

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,	
	2017	**2016**
Operating activities		
Net margins including noncontrolling interest	$ 28,990	$ 20,251
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	87,762	80,776
Amortization of intangible asset	3,662	3,662
Amortization of NRECA Retirement Security Plan prepayment	2,686	2,686
Amortization of debt issuance costs	1,003	940
Impairment loss - Holcomb Expansion	93,494	—
Deferred Holcomb Expansion impairment loss	(93,494)	—
Deferred membership withdrawal income	—	47,572
Recognition of deferred membership withdrawal income	(5,000)	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,233)	(2,190)
Recognition of deferred revenue	(15,000)	—
Change in restricted cash and investments	(78)	(78)
Changes in operating assets and liabilities:		
Accounts receivable	(13,382)	(3,424)
Coal inventory	8,049	(2,965)
Materials and supplies	1,376	(1,224)
Accounts payable and accrued expenses	6,703	3,475
Accrued interest	(1,729)	(312)
Accrued property taxes	(10,597)	(9,431)
Other deferred credits - TEP transmission settlement	(15,521)	—
Other deferred credits - TEP transmission refund	—	2,313
Other	(17,557)	(9,811)
Net cash provided by operating activities	**60,134**	**132,240**
Investing activities		
Purchases of plant	(98,150)	(93,953)
Changes in deferred charges	321	(7,698)
Proceeds from other investments	61	313
Net cash used in investing activities	**(97,768)**	**(101,338)**
Financing activities		
Changes in Member advances	(5,799)	754
Payments of long-term debt	(100,393)	(408,584)
Proceeds from issuance of debt	—	307,135
Increase in short-term borrowings, net	120,305	94,948
Proceeds from investment in securities pledged as collateral	—	4,647
Retirement of patronage capital	(3,023)	(15,345)
Other	82	(231)
Net cash provided by (used in) financing activities	**11,172**	**(16,676)**
Net increase (decrease) in cash and cash equivalents	**(26,462)**	**14,226**
Cash and cash equivalents – beginning	**165,893**	**144,587**
Cash and cash equivalents – ending	**$ 139,431**	**$ 158,813**
Supplemental cash flow information:		
Cash paid for interest	$ 80,729	$ 78,696
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (2,776)	$ (4,525)

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, 2017 and 2016

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, 2016 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, 2017, results of operations for the three and six months ended June 30, 2017 and 2016, and cash flows for the six months ended June 30, 2017 and 2016 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 12 – 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 three 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), the Missouri Basin Power Project ("MBPP") (operated by Basin Electric Power Cooperative ("Basin")) and the San Juan Project (operated by Public Service Company of New Mexico). 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, 2017 (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 %	$ 349,958	$ 235,028	$ 46,928
MBPP - Laramie River Station	24.13 %	409,998	297,022	15,787
San Juan Project – San Juan Unit 3	8.20 %	82,688	77,138	—
Total		$ 842,644	$ 609,188	$ 62,715

Depreciation Rates

Effective January 1, 2017, we adopted depreciation rates that reflect rates determined in a depreciation rate study for our transmission plant and most of our general plant. We expect that the new rates will result in a reduction in 2017 transmission and general plant depreciation expense of approximately $20.0 million. A depreciation rate study has been performed during 2017 for our generation plant and these rates will be adopted prospectively beginning July 1, 2017. We expect that the new rates will result in an increase in 2017 generation plant depreciation expense of approximately $0.5 million.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform to the 2017 presentation.

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, 2017	December 31, 2016
Regulatory assets		
Deferred income tax expense (1)	$ 30,517	$ 30,517
Deferred prepaid lease expense – Craig Unit 3 Lease (2)	6,473	9,710
Deferred prepaid lease expense – Springerville Unit 3 Lease (3)	89,441	90,587
Goodwill – J.M. Shafer (4)	56,268	57,692
Goodwill – Colowyo Coal (5)	39,777	40,294
Deferred debt prepayment transaction costs (6)	162,502	166,815
Deferred Holcomb Expansion impairment loss (7)	93,494	—
Total regulatory assets	478,472	395,615
Regulatory liabilities		
Interest rate swaps (8)	9,357	12,140
Deferred revenues (9)	20,800	35,800
Membership withdrawal (10)	42,572	47,572
Total regulatory liabilities	72,729	95,512
Net regulatory asset	$ 405,743	$ 300,103

(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) Deferral of loss on acquisition related to the Craig Generating Station Unit 3 (“Craig Unit 3”) prepaid lease expense upon acquisitions of equity interests in 2002 and 2006. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of $6.5 million annually through the remaining original life of the lease ending June 30, 2018 and recovered from our Members in rates.

(3) Deferral of 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.

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

(5) 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.

(6) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of $8.6 million annually over the 21.4-year average life of the new debt issued and recovered from our Members in rates.

(7) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights, for a new coal-fired generating unit or units at Holcomb Generating Station ("Holcomb Expansion"). On March 17, 2017, the Kansas Supreme Court issued a decision upholding the air permit for one unit at Holcomb Generating Station of 895 megawatts. The air permit expires if construction of the Holcomb Expansion does not commence within 18 months. Although a final decision has not been made by our Board on whether to proceed with the construction of the Holcomb Expansion, we have assessed the probability of us entering into construction for the Holcomb Expansion as remote. Based on this assessment, we have determined that the costs incurred for the Holcomb Expansion are impaired and not recoverable. At the discretion of our Board, the impaired loss has been deferred as a regulatory asset and will be recovered from our Members in rates. The plan for the recovery 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. See Note 5 – Other Deferred Charges.

(8) Represents deferral of the unrealized gain related to the change in fair value of forward starting interest rate swaps that were entered into in order to hedge interest rates on anticipated future borrowings. Upon settlement of these interest rate swaps, the realized gain or loss will be amortized to interest expense over the term of the associated long-term debt borrowing. See Note 6 – Long-Term Debt and Note 11 – Fair Value.

(9) Represents deferral of the recognition of $10 million of non-member electric sales revenue received in 2008 and $35 million of non-member electric sales revenue received in 2011. $9.2 million of this deferred revenue was recognized in non-member electric sales revenue in 2016. As part of our Board approving the A-40 rate schedule, which was implemented on January 1, 2017, the Board approved the income recognition in 2017 of $10.0 million of previously deferred 2008 non-member electric sales revenue and $20.0 million of previously deferred 2011 non-member electric sales revenue. $15.0 million of this deferred revenue was recognized in non-member electric sales revenue for the six-month period ended June 30, 2017. The remaining 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 of $47.6 million recorded in connection with the June 30, 2016 withdrawal of Kit Carson Electric Cooperative, Inc. from membership in us. As part of our Board approving the A-40 rate schedule, which was implemented on January 1, 2017, the Board approved the income recognition in 2017 of $10.0 million of deferred membership withdrawal income. $5.0 million of this deferred membership withdrawal income was recognized in other income for the six-month period ended June 30, 2017. The remaining 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 (accounted for using the cost method) and other required investments in the organizations. Under this method, 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.

NOTE 4 – RESTRICTED CASH AND INVESTMENTS

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.

NOTE 5 – OTHER DEFERRED CHARGES

We make expenditures for preliminary surveys and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects. If construction results, the preliminary survey and investigation expenditures will be reclassified to electric plant - construction work in progress. If the work is abandoned, the related preliminary survey and investigation expenditures will be charged to the appropriate operating expense account or the expense could be deferred as a regulatory asset to be recovered from our Members in rates subject to approval by our Board, which has budgetary and rate-setting authority. Preliminary surveys and investigations was primarily comprised of expenditures for the Holcomb Expansion of $91.3 million as of December 31, 2016. There was no balance for the Holcomb Expansion as of June 30, 2017 because we have determined that the costs incurred for the Holcomb Expansion have been impaired. The impairment loss was deferred at the discretion of our Board. See Note 2 – Accounting for Rate Regulation.

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, Yampa Project – Craig Generating Station Units 1 and 2, and San Juan Project – San Juan Unit 3. We also make advance payments to the operating agent of Springerville Unit 3.

In 2016, we entered into forward starting interest rate swaps to hedge a portion of our future long-term debt interest rate exposure. The unrealized gain on these interest rate swaps, as of June 30, 2017, was deferred in accordance with the accounting requirements related to regulated operations. See Note 2 – Accounting for Rate Regulation.

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

	June 30, 2017	December 31, 2016
Preliminary surveys and investigations	$ 21,013	$ 111,592
Advances to operating agents of jointly owned facilities	11,693	11,871
Interest rate swaps	9,357	12,140
Other	4,691	3,775
Total other deferred charges	$ 46,754	$ 139,378

NOTE 6 – LONG-TERM DEBT

The mortgage notes payable and pollution control revenue bonds of $2.7 billion are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates of $419 million are secured by the assets of Springerville Unit 3. We also have three unsecured notes in the aggregate amount of $45.9 million as of June 30, 2017. 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 Bank of America, N.A. and CoBank, ACB as Joint Lead Arrangers in the amount of $750 million (“Revolving Credit Agreement”) that expires on July 26, 2019. We had no outstanding borrowings as of June 30, 2017 and December 31, 2016. There is a 364-day, direct pay letter of credit issued under the Revolving Credit Agreement and provided by Bank of America, N.A. for the $46.8 million Moffat County, CO pollution control revenue bonds. As of June 30, 2017, we have $462.1 million in total aggregate availability (including $259.8 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

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

	June 30, 2017	December 31, 2016
Total debt	$ 3,159,329	$ 3,259,721
Less debt issuance costs	(21,342)	(22,255)
Less debt discounts	(10,466)	(10,569)
Plus debt premiums	19,803	20,711
Total debt adjusted for discounts, premiums and debt issuance costs	3,147,324	3,247,608
Less current maturities	(77,337)	(107,903)
Long-term debt	$ 3,069,987	$ 3,139,705

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 have entered into forward starting interest rate swaps to hedge a portion of our future long-term debt interest rate exposure. We anticipate settling these swaps in conjunction with the issuance of future long-term debt. See Note 2 - Accounting for Rate Regulation and Note 11 - Fair Value.

The terms of the interest rate swap contracts are as follows (dollars in thousands):

	Notional Amount	Fixed Rate (1)	Benchmark Interest Rate (2)	Effective Date	Maturity Date
Interest rate swap - April 2016	$ 90,000	2.355 %	30 year - LIBOR	April 2019	April 2049
Interest rate swap - June 2016	80,000	2.304	30 year - LIBOR	June 2019	June 2049
	$ 170,000				

(1) We will pay.
(2) We will receive.

NOTE 7 – SHORT-TERM BORROWINGS

We have a commercial paper program under which we issue unsecured commercial paper in aggregate amounts not exceeding the commercial paper sublimit under our Revolving Credit Agreement, which was $500 million at June 30, 2017. 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, 2017	December 31, 2016
Commercial paper outstanding, net of discounts	$ 240,206	$ 119,901
Weighted average interest rate	1.35 %	0.89 %

At June 30, 2017, $259.8 million of the commercial paper back-up sublimit remained available under the Revolving Credit Agreement. See Note 6 – Long-Term Debt.

NOTE 8 – 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 in a manner consistent with the depreciation of the underlying physical asset. In the absence of quoted market prices, we determine fair value by using present value techniques in which estimates of future cash flows associated with retirement activities are discounted using a credit adjusted risk-free rate and market risk premium. Upon settlement of an asset retirement obligation, we will apply payment against the estimated liability and incur a gain or loss if the actual retirement costs differ from the estimated recorded liability. These liabilities are included in asset retirement obligations.

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. New Horizon Mine started final reclamation June 8, 2017.

Generation: We, including 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.

Transmission: We have an asset retirement obligation to remove a certain transmission line and related substation assets resulting from an agreement to relocate the line.

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

	June 30,
	2017
Asset retirement obligation at beginning of period	$ 58,583
Liabilities incurred	456
Liabilities settled	(500)
Accretion expense	1,246
Change in cash flow estimate	(3,805)
Asset retirement obligation at end of period	$ 55,980

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

NOTE 9 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES

In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. $34.5 million will be paid by us for these easements from 2017 through the individual easement terms ending between 2036 and 2040. The present value for the easement payments were $21.4 and $20.6 million as of June 30, 2017 and December 31, 2016, respectively, which is recorded as other deferred credits and other liabilities.

We received $15.5 million in 2016 from Tucson Electric Power Company (“TEP”) as ordered by the United States Federal Energy Regulatory Commission (“FERC”). In 2015, TEP filed various non-conforming point-to-point transmission services agreements with FERC, including transmission services agreements between TEP and us. FERC ordered TEP to make a time value refund to us with regard to these transmission services agreements. TEP appealed the FERC order and stated that the funds were subject to refund in the event TEP was ultimately successful in its appeal. In

2016, due to uncertainties regarding the ultimate outcome of this matter, we recorded the total receipt of $15.5 million in other deferred credits.

On January 12, 2017, we entered into a settlement agreement with TEP and TEP moved to dismiss the appeal with prejudice. We returned $7.75 million to TEP and recognized $7.75 million that we retained as a reduction in transmission expense on our statement of operations during the first quarter of 2017.

We have received upfront payments from others for the use of optical fiber and these are reflected in unearned revenue until recognized over the life of the agreement. We have received deposits from various parties and those that may still be required to be returned are a liability and these are reflected in customer deposits.

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

	June 30, 2017	December 31, 2016
Transmission easements	$ 21,430	$ 20,562
TEP transmission refund	—	15,521
Unearned revenue	3,755	4,000
Customer deposits	3,002	3,338
Other	21,300	22,743
Total other deferred credits and other liabilities	$ 49,487	$ 66,164

NOTE 10 – 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. Accordingly, 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. We had an income tax benefit of $0.6 million for the six months ended June 30, 2017 and income tax expense of $0.4 million for the six months ended June 30, 2016. The 2017 income tax benefit of $0.6 million is due to an alternative minimum tax credit refund in lieu of bonus depreciation.

NOTE 11 – 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 classified as available-for-sale and are measured at fair value on a recurring basis. 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 unrealized gains are reported as a component of accumulated other comprehensive income. The amortized cost and fair values of our marketable securities are as follows (dollars in thousands):

	As of June 30, 2017		As of December 31, 2016	
	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Marketable securities	$ 845	$ 1,007	$ 987	$ 1,103

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 $45.2 million as of June 30, 2017 and $49.1 million as of December 31, 2016, respectively.

Debt

The fair values of debt were estimated using discounted cash flow analyses based on our current incremental borrowing rates for similar types of borrowing arrangements. These valuation assumptions utilize observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs). The principal amounts and fair values of our debt are as follows (dollars in thousands):

	As of June 30, 2017		As of December 31, 2016	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,159,329	$ 3,457,045	$ 3,259,721	$ 3,543,640

Interest Rate Swaps

We entered into forward starting interest rate swaps in 2016 to hedge a portion of our future long-term debt interest rate expense. See Note 6 – Long-Term Debt. These interest rate swaps are derivative instruments in accordance with ASC 815, Derivatives and Hedging, and are recorded at fair value on a recurring basis. The estimated fair value of these interest rate swaps utilizes 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) and are included in other deferred credits and other liabilities on our consolidated statements of financial position. At June 30, 2017, the fair value of our interest rate swaps was an unrealized gain of $9.4 million, which was deferred in accordance with our regulatory accounting. See Note 2 – Accounting for Rate Regulation.

NOTE 12 – 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.

Our consolidated statements of financial position include the Springerville Partnership's net electric plant of $821.8 million and $832.3 million at June 30, 2017 and December 31, 2016, respectively, the long-term debt of $432.1 million and $472.1 million at June 30, 2017 and December 31, 2016, respectively, accrued interest associated with the long-term debt of $12.4 million and $13.4 million at June 30, 2017 and December 31, 2016, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $109.8 million and $109.1 million at June 30, 2017 and December 31, 2016, respectively.

Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $5.2 million for the three months ended June 30, 2017 and the comparable period in 2016. Our consolidated statements of operations also include interest expense of $7.1 million for the three months ended June 30, 2017 and $7.6 million for the comparable period in 2016. Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $10.5 million for the six months ended June 30, 2017 and the comparable period in 2016. Our consolidated statements of operations also include interest expense of $14.3 million for the six months ended June 30, 2017 and $15.3 million for the comparable period in 2016. 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. 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.

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 and spot coal for the Springerville Unit 3 in Arizona. 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 isn't 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 $2.2 million at June 30, 2017 and December 31, 2016, 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 24.13 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 isn't 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.

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 isn't 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 $14.8 million at June 30, 2017 and $14.5 million at December 31, 2016.

NOTE 13 – LEGAL

Other than as disclosed below, there are no new material litigation or proceedings pending or threatened against us or any material developments in any material existing pending litigation or proceedings.

We have an option to purchase development rights for the Holcomb Expansion pursuant to a Purchase Option and Development Agreement ("PODA"). The July 2007 PODA with Sunflower and other Sunflower parties calls for us to make option payments totaling $55 million to Sunflower and/or the other Sunflower parties in exchange for the development rights. Upon execution of the PODA, we paid $25 million. In 2008, we paid $5 million and the remainder would be paid on the purchase date. The purchase date will be designated by us, Sunflower and the other parties to the PODA after we exercise our option to acquire the development rights. The purchase date has not been determined. After various appeals related to the air permit, on March 17, 2017, the Kansas Supreme Court issued a decision upholding the air permit issued by the Kansas Department of Health and Environment for one new coal-fired generating unit at Holcomb Generating Station of 895 megawatts. Our Board has not made a decision to proceed with the construction of this project, including whether or not to exercise our option to acquire the development rights. Excluding the cost of land and water rights, we have determined that the cost incurred for developing the Holcomb Expansion of $93.5 million as of June 30, 2017 has been impaired. The impairment loss was deferred at the discretion of our Board. See Note 2 – Accounting for Rate Regulation.

In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five weeks in northern New Mexico, primarily on national forest service land in the Santa Fe National Forest. Six plaintiff groups, composed of property owners in the area of the Las Conchas Fire, filed separate lawsuits against our Member, Jemez Mountains Electric Cooperative, Inc. ("JMEC") in the Thirteenth District Court, Sandoval County in the State of New Mexico.

Plaintiffs alleged that the fire ignited when a tree growing outside JMEC's right of way fell onto a distribution line owned by JMEC as a result of high winds. On January 7, 2014, the district court allowed all parties and related parties to amend their complaints to include the addition of us as a party defendant. After JMEC settled with one plaintiff group, the remaining cases were Elizabeth Ora Cox, et al., v. Jemez Mountains Electric Cooperative, Inc., et al.; Norman Armijo, et al., v. Jemez Mountains Electric Cooperative, Inc., et al.; Esequiel Espinoza, et al. v. Allstate Property & Casualty, et al.; Jemez Pueblo v. Jemez Mountains Electric Cooperative, Inc., et al.; and Pueblo de Cochiti., et al. v. Jemez Mountains Electric Cooperative, Inc., et al. The allegations in each case were similar. Plaintiffs alleged that we owed them independent duties to inspect and maintain the right-of-way for JMEC's distribution line and that we were also jointly liable for any negligence by JMEC under joint venture and joint enterprise theories. A jury trial commenced on September 28, 2015 on the liability aspect of this matter. On October 28, 2015, the jury affirmed our position that we and JMEC did not operate as a joint venture or joint enterprise. The jury did find we owed the plaintiffs an independent duty and allocated comparative negligence with JMEC 75 percent negligent, us 20 percent negligent, and the United States Forest Service 5 percent negligent. Although we have not settled this matter, we have reached separate confidential stipulations on damages with all plaintiff groups, reserving the right to appeal liability issues. We maintain $100 million in liability insurance coverage for this matter. We anticipate appealing the determination of our liability for this matter. If we do not prevail on appeal, we expect our allocation of damages to be covered by our liability insurance. Although we cannot predict the outcome of this matter at this point in time, we do not expect them to have a material adverse effect on our financial condition or our future results of operations or cash flows.

For further discussion regarding legal proceedings, see our annual report on Form 10-K for the year ended December 31, 2016 "Item 8 – FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA – Notes to Consolidated Financial Statements – Note 13 - Commitments and Contingencies – Legal."

NOTE 14 – NEW ACCOUNTING PRONOUNCEMENTS

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-07, *Compensation-Retirement Benefits (Topic 715)-Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. This amendment disaggregates the accounting for the service cost component of the net periodic benefit cost of an entity's defined benefit pension and other postretirement benefit plans from the other components of the net periodic benefit cost (such as interest expense, recognition of actuarial gain or loss on postretirement benefit obligations, and amortization of prior service cost or credit). The service cost component is to be included in the same income statement line item(s) as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be included separately from the line item(s) that include service cost and outside of any subtotal of operating income, if one is presented. ASU 2017-07 also limits the portion of net benefit cost that is eligible for capitalization to property, plant and equipment to the current service cost component. This amendment is effective for fiscal years beginning after December 31, 2017, including interim periods within those annual periods. Early adoption is permitted. The guidance is applied using a full retrospective transition method. We are currently evaluating the impact that this amendment will have on our results of operations.

In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230) – Restricted Cash*. This amendment requires the statement of cash flows to explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts described as restricted cash and restricted cash equivalents will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This amendment is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted. The guidance is applied using a full retrospective transition method. We are currently evaluating the impact that this amendment will have on our statement of cash flows.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230) – Classification of Certain Cash Receipts and Payments.* This amendment provides specific guidance on certain cash flow presentation and classification issues in order to reduce diversity in practice on the statement of cash flows. The issues that primarily relate to us are the classification of proceeds from the settlement of insurance claims and distributions received from equity method investees. This amendment is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted. The guidance is applied using a full retrospective transition method. We are currently evaluating the impact that this amendment will have on our statement of cash flows.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* This amendment requires a lessee to recognize substantially all leases (whether operating or finance leases) on the balance sheet as a right-of-use asset and an associated lease liability. Short-term leases of 12 months or less are excluded from this amendment. A right-of-use asset represents a lessee's right to use (control the use of) the underlying asset for the lease term. A lease liability represents a lessee's liability to make lease payments. The right-of-use asset and the lease liability are initially measured at the present value of the lease payments over the lease term. For finance leases, the lessee subsequently recognizes interest expense and amortization of the right-of-use asset, similar to accounting for capital leases under current GAAP. For operating leases, the lessee subsequently recognizes straight-line lease expense over the life of the lease. Lessor accounting remains substantially the same as that applied under current GAAP. This amendment is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. The guidance is to be applied using a modified retrospective transition method with the option to elect a package of practical expedients. We are currently evaluating the impact of this amendment on our financial position and results of operations.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. This amendment requires an entity to measure investments in equity securities, except those that result in consolidation or are accounted for under the equity method of accounting, at fair value with changes in fair value recognized in net income. For equity investments that do not have readily determinable fair value and don't qualify for the existing practical expedient in ASC 820, *Fair Value Measurements*, to estimate fair value using the net asset value per share of the investment, the guidance provides a new measurement alternative. Entities may choose to measure those investments at cost, less any impairment, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investment of the same issuer. This amendment also affects financial liabilities using the fair value option and the presentation and disclosure requirements for financial instruments. Also, an entity should present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk if the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. The amendments are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application by public business entities to financial statements of fiscal years or interim periods that have not yet been issued or, by all other entities, that have not yet been made available for issuance are permitted as of the beginning of the fiscal year of adoption. An entity should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The amendments related to equity securities without readily determinable fair values (including disclosure requirements) should be applied prospectively to equity investments that exist as of the date of adoption of the update. We are currently evaluating the impact of this amendment on our financial position and results of operations.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606),* as amended by subsequent ASU amendments issued in 2015 and 2016. The core principle under the new revenue standard requires that revenue should be recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. To achieve the core principle, the following steps are required: (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This amendment also requires enhanced quantitative and qualitative disclosures to enable users of financial information to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. This amendment is effective for the fiscal year beginning January 1, 2018 using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach with the cumulative effect of initially adopting the standard recognized at the date of adoption (which includes footnote disclosures). While we have not yet selected a transition method, we currently expect to use the modified retrospective approach. We are currently evaluating the impact of Topic 606, including the transition method, on our financial position and results of operations.

Our evaluation process includes, but is not limited to, identifying contracts within the scope of Topic 606, reviewing the contracts, and documenting our analysis of these contracts. We have evaluated our wholesale electric service contracts with our 43 Members, which was $574.7 million, or 85 percent, of our operating revenue for the six months ended June 30, 2017. Our Members are billed on a monthly basis per an energy rate and demand rate(s) for energy consumed during the period. We transfer control of the electricity over time and the Member simultaneously receives and consumes the benefits of the electricity. The amount we invoice a Member on a monthly basis corresponds directly with the value to the Member of our performance. Accordingly, we do not believe there will be material impact to our recognition of revenue from the sale of electricity to our Members. We have evaluated the significant contracts for our non-member electric sales revenue. Our non-member electric sales revenue was $60.5 million, or 9 percent, of our operating revenue for the six months ended June 30, 2017. We do not believe there will be a material impact to our recognition of revenue from the sale of electricity to non-members. We are currently evaluating the impact of the new standard on our remaining operating revenue.

The American Institute of Certified Public Accountants Power and Utilities Revenue Recognition Task Force is currently assessing the impact of this update on contributions in aid of construction ("CIAC"). CIAC represents funds collected from Members as an investment in property, plant and equipment. CIAC is recorded as a reduction in the total cost basis of property, plant and equipment such that only the net cost to us is included in property, plant and equipment on our statements of financial position, in accordance with standard industry practice. This net amount (after contribution) is the amount subject to ratemaking. If it is determined that CIAC is within the scope of Topic 606, it could have a material impact on our financial position and results of operations.

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 member distribution systems, or Members, that serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We currently have 43 Members after the withdrawal in June 2016 of Kit Carson Electric Cooperative, Inc., or KCEC, from membership in us. 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 rural residences, farms and ranches, cities, towns and suburban communities, as well as large and small businesses and industries. As of June 30, 2017, our Members served approximately 600,000 retail electric meters over a nearly 200,000 square-mile area. We sold 8.6 million megawatt hours, or MWhs, for the six months ended June 30, 2017, of which 88.7 percent was to Members. Total revenue from electric sales was $635.1 million for the six months ended June 30, 2017, of which 90.5 percent was from Member sales.

We have entered into substantially similar wholesale electric service contracts with each Member extending through 2050 for 42 Members (which constitute approximately 96.7 percent of our revenue from Member sales for the six months ended June 30, 2017) and extending through 2040 for the remaining Member (Delta-Montrose Electric Association). These contracts are subject to automatic extension thereafter until either party provides at least two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Member and obligates the Member to purchase and receive 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, 2017, 22 Members were enrolled in this program with capacity totaling approximately 145 megawatts.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating and transmission facilities, long-term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or have tolling arrangements with respect to, various generating stations. Additionally, we transmit power to our Members through resources that we own, lease or have undivided percentage interests in, or by wheeling power across lines owned by other transmission providers.

Critical Accounting Policies

As of June 30, 2017, 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, 2016.

Factors Affecting Results

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 statement 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 of Directors, or 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. Pursuant to the policy, we target rates payable by our Members to produce financial results in excess of the requirements under our indenture, dated effective as of December 15, 1999, or Master Indenture, between us and Wells Fargo Bank, National Association, as trustee. On a periodic basis, our Board will determine whether to retire any patronage capital, and in what amounts, to our Members.

As of June 30, 2017, patronage capital equity was $989.7 million. To date, we have retired approximately $335.5 million of patronage capital to our Members.

Rates and Regulation

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Rates for electric power sales to our Members consist of two billing components: an energy rate and demand rates. Member rates for energy and demand are set by our Board, consistent with adequate electrical reliability and sound fiscal policy. The energy rate is billed based upon a price per kilowatt hour, or kWh, of physical electricity delivered through our transmission system 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.

Approved by our Board in September 2016 and effective January 1, 2017, we implemented the A-40 rate schedule. The A-40 rate schedule increased the average budgeted Member cents/kWh for 2017 by 4.23 percent compared to the average budgeted Member cents/kWh for 2016. In 2016, our A-39 rate, which had the same rate design as our 2017 wholesale A-40 rate, was in effect.

Although rates established by our Board are generally not subject to regulation by federal, state or other governmental agencies, we are currently required to submit our rates to the New Mexico Public Regulation Commission, or NMPRC. The NMPRC 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.

No New Mexico Member filed a protest with the NMPRC for the A-40 rate or the A-39 rate and thus these rates were effective without NMPRC review or approval.

Master Indenture

As of June 30, 2017, we had approximately $2.7 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Our Master Indenture requires us to establish rates annually that are reasonably expected to achieve a 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.

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. Accordingly, 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.

Results of Operations

General

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Rates for electric power sales to our Members consist of two billing components: an energy rate and demand rates. 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. Relatively higher summer or lower winter temperatures tend to increase the usage of electricity for heating, air conditioning and irrigation. Mild weather generally reduces the usage of electricity because heating, air conditioning and irrigation systems are operated less frequently. The amount of precipitation during the growing season (generally May through September) also impacts irrigation use. Other factors affecting our Members' usage of electricity include:

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

Three months ended June 30, 2017 compared to three months ended June 30, 2016

Operating Revenues

Member electric sales increased 64,222 MWhs to 3,834,489 MWhs for the three months ended June 30, 2017 compared to 3,770,267 MWhs for the same period in 2016. The withdrawal of KCEC in June 2016 resulted in a 60,017 MWhs decrease for the three months ended June 30, 2017 compared to the same period in 2016, which was more than offset by an increase in sales to other Members. The increase in MWhs sold in 2017 resulted in an increase of $16.8 million, or 6.1 percent, in Member electric sales revenue to $292.3 million for the three months ended June 30, 2017 compared to $275.5 million for the same period in 2016. The increase in member electric sales revenue was primarily due to the A-40 rate schedule effective January 1, 2017, partially offset by the decrease in revenue of $4.4 million as a result of the withdrawal of KCEC from membership in us.

Non-member electric sales decreased 190,526 MWhs, or 34.7 percent, to 357,861 MWhs for the three months ended June 30, 2017 compared to 548,387 MWhs for the same period in 2016. Non-member electric sales revenue increased $0.2 million to $25.3 million for the three months ended June 30, 2017 compared to $25.1 million for the same period in 2016. The primary reason for the increase in non-member electric sales revenue was due to the income recognition of $7.5 million of previously deferred 2011 and 2008 non-member electric sales revenue. This recognition in 2017 was approved by our Board in accordance with its budgetary and rate-setting authority. Excluding the effect of the previously deferred non-member electric sales revenue recognition, non-member electric sales revenue decreased $7.3 million, or 29.1 percent, to $17.8 million for the three months ended June 30, 2017 compared to $25.1 million for the same period in 2016. The decrease in MWhs sold and non-member electric sales was primarily due to the expiration of a long-term power sales arrangement in March 2017.

Operating Expenses

Purchased power increased 63,460 MWhs, or 3.5 percent, to 1,871,782 MWhs for the three months ended June 30, 2017 compared to 1,808,322 MWhs for the same period in 2016. Purchased power expense increased $5.8 million, or 7.6 percent, to $82.4 million for the three months ended June 30, 2017 compared to $76.6 million for the same period in 2016. The increase in purchased power expense was primarily due to an increase of $5.7 million, or 60.0 percent, to $15.2 million for the three months ended June 30, 2017 compared to $9.5 million for the same period in 2016 for relatively similar MWh purchases from a new wind generating facility. Our purchases of power from the new wind generating facility had a higher average cost per MWh for the three months ended June 30, 2017 compared to the same period in 2016 when we were paying a lower pre-commercial rate. Additionally, purchased power expense from Basin Electric Power Cooperative, or Basin, increased $2.9 million for the three months ended June 30, 2017 compared to the same period in 2016 for relatively similar MWh purchases due to Basin's rate increase in third quarter 2016.

Fuel expense includes, coal, natural gas and other fuel consumed at the generating stations. Fuel expense increased $6.9 million, or 13.5 percent, to $58.5 million for the three months ended June 30, 2017 compared to $51.6 million for the same period in 2016. Fuel expense increased primarily due to higher coal costs and higher generation at the Nucla Generating Station for the three months ended June 30, 2017 compared to the same period in 2016. The increases in coal expense were partially offset by lower generation in the second quarter 2017 due to planned outages at the Escalante Generating Station and the Craig Generating Station.

Depreciation, amortization and depletion expense decreased $0.8 million to $41.1 million for the three months ended June 30, 2017 compared to $41.9 million for the same period in 2016. Depreciation, amortization and depletion expense decreased for the three months ended June 30, 2017 primarily due to a decrease of depreciation expense on transmission assets as a result of the transmission rate study that was effective January 1, 2017. The decrease was partially offset by an increase in depreciation expense due to the shortened lives of several assets. The Nucla Generating Station depreciation expense increased approximately $2.1 million due to the shortened life associated with the anticipated December 31, 2022 retirement date of the unit. The Craig Generating Station Unit 1 depreciation expense increased approximately $0.6 million due to the shortened life associated with the anticipated December 31, 2025 retirement date of the unit.

Other Income

Other income increased $2.3 million, or 116.6 percent, to $4.2 million for the three months ended June 30, 2017 compared to $1.9 million for the same period in 2016. The increase in other income was primarily due to the recognition of $2.5 million of deferred membership withdrawal income for the three months ended June 30, 2017 related to the June 30, 2016 withdrawal of KCEC from membership in us. Our Board approved recognizing $10.0 million of deferred membership withdrawal income in 2017.

Six months ended June 30, 2017 compared to six months ended June 30, 2016

Operating Revenues

Member electric sales increased 15,689 MWhs to 7,615,389 MWhs for the six months ended June 30, 2017 compared to 7,599,700 MWhs for the same period in 2016. The withdrawal of KCEC in June 2016 resulted in a 144,324 MWhs decrease for the six months ended June 30, 2017 compared to the same period in 2016, which was more than offset by an increase in sales to other Members. The increase in MWhs sold in 2017 resulted in an increase of $27.4 million, or 5.0 percent, in Member electric sales revenue to $574.7 million for the six months ended June 30, 2017 compared to $547.3 million for the same period in 2016. The increase in member electric sales revenue was primarily due to the A-40 rate schedule effective January 1, 2017, partially offset by the decrease in revenue of $10.5 million as a result of the withdrawal of KCEC from membership in us.

Non-member electric sales decreased 135,414 MWhs, or 12.3 percent, to 968,058 MWhs for the six months ended June 30, 2017 compared to 1,103,472 MWhs for the same period in 2016. Non-member electric sales revenue increased $5.3 million, or 9.6 percent, to $60.5 million for the six months ended June 30, 2017 compared to $55.2 million for the same period in 2016. The primary reason for the increase in non-member electric sales revenue was due to the income recognition of $15.0 million of previously deferred 2011 and 2008 non-member electric sales revenue. This recognition in 2017 was approved by our Board in accordance with its budgetary and rate-setting authority. Excluding the effect of the previously deferred non-member electric sales revenue recognition, non-member electric sales revenue decreased $9.7 million, or 17.6 percent, to $45.5 million for the six months ended June 30, 2017 compared to $55.2 million for the same period in 2016. The decrease in MWhs sold and non-member electric sales was primarily due to the expiration of a long-term power sales arrangement in March 2017.

Operating Expenses

Purchased power increased 35,176 MWhs to 3,496,750 MWhs for the six months ended June 30, 2017 compared to 3,461,574 MWhs for the same period in 2016. Purchased power expense increased $11.2 million, or 7.6 percent, to $158.8 million for the six months ended June 30, 2017 compared to $147.6 million for the same period in 2016. The increase in purchased power expense was primarily due to a $9.4 million increase, or 48.5 percent, to $28.8 million for the six months ended June 30, 2017 compared to $19.4 million for the same period in 2016 for relatively similar MWh purchases from a new wind generating facility. Our purchases of power from the new wind generating facility had a higher average cost per MWh for the six months ended June 30, 2017 compared to the same period in 2016 when we were paying a lower pre-commercial rate. Additionally, purchased power expense from Basin increased $5.4 million for the six months ended June 30, 2017 compared to the same period in 2016 for relatively similar MWh purchases due to Basin's rate increase in third quarter 2016.

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense increased $6.7 million, or 6.0 percent, to $119.3 million for the six months ended June 30, 2017 compared to $112.6 million for the same period in 2016. The increase was primarily due to higher coal expense at the Nucla Generating Station and higher coal costs from the Colowyo Mine and New Horizon Mine. The increase in coal expense was partially offset by a decrease in generation of 196,560 MWhs to 5,434,344 MWhs for the six months ended June 30, 2017 compared to 5,630,904 MWhs for the same period in 2016.

Depreciation, amortization and depletion expense increased $7.0 million, or 8.6 percent, to $87.8 million for the six months ended June 30, 2017 compared to $80.8 million for the same period in 2016. Depreciation, amortization and depletion expense increased for the six months ended June 30, 2017 primarily due to the shortened lives of several assets. The Nucla Generating Station depreciation expense increased approximately $4.2 million due to the shortened life associated with the anticipated December 31, 2022 retirement date of the unit. New Horizon Mine, which provides coal to the Nucla Generating Station, depreciation, amortization and depletion expense increased approximately $4.3 million due to the shortened life. The Craig Generating Station Unit 1 depreciation expense increased approximately $1.2 million due to the shortened life associated with the anticipated December 31, 2025 retirement date of the unit. The remaining increase in expense was primarily due to additions of equipment throughout our transmission system and at our generating stations. The increase was primarily offset by a decrease in depreciation expense on transmission assets due to the transmission rate study that was effective January 1, 2017.

Other Income

Other income increased $4.4 million, or 52.4 percent, to $13.0 million for the six months ended June 30, 2017 compared to $8.6 million for the same period in 2016. The increase in other income was primarily due to the recognition of $5.0 million of deferred membership withdrawal income for the six months ended June 30, 2017 related to the June 30, 2016 withdrawal of KCEC from membership in us. Our Board approved recognizing $10.0 million of deferred membership withdrawal income in 2017.

Financial condition as of June 30, 2017 compared to December 31, 2016

Assets

Other plant consists of mine assets and non-utility assets (which consist of piping and equipment specifically related to providing steam and water from the Escalante Generating Station to a third party for the use in the production of paper). Other plant increased $12.6 million, or 5.4 percent, to $247.1 million as of June 30, 2017 compared to $234.5 million as of December 31, 2016. The increase was primarily due to capital expenditures for the development of the Collom mining pit at the Colowyo Mine.

Deposits and advances increased $15.6 million, or 62.0 percent, to $40.7 million as of June 30, 2017 compared to $25.1 million as of December 31, 2016. 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.

Accounts receivable-Members increased $16.8 million, or 17.1 percent, to $114.7 million as of June 30, 2017 compared to $97.9 million as of December 31, 2016. The increase was primarily due to higher Member electric sales revenue in June 2017 compared to December 2016.

Regulatory assets increased $82.9 million, or 20.9 percent, to $478.5 million as of June 30, 2017 compared to $395.6 million as of December 31, 2016. The increase was due to the impairment loss of $93.5 million for development costs for a new coal-fired generating unit or units at Holcomb Generating Station, or Holcomb Expansion. This impairment loss was partially offset by amortization of $10.6 million to depreciation, amortization and depletion expense for recovery from our Members in rates.

Other deferred charges decreased $92.6 million, or 66.5 percent, to $46.8 million as of June 30, 2017 compared to $139.4 million as of December 31, 2016. The decrease was primarily due to the impairment loss of $93.5 million for the development costs for the Holcomb Expansion. In June 2017, we determined that the costs for the Holcomb Expansion were impaired. The impairment loss was deferred in accordance with the accounting requirements related to regulated operations at the discretion of our Board, which has budgetary and rate-setting authority.

Equity and Liabilities

Patronage capital equity increased $28.3 million to $989.7 million as of June 30, 2017 compared to $961.4 million as of December 31, 2016. The increase was primarily due to a margin attributable to us of $28.3 million for the six months ended June 30, 2017.

Short-term borrowings consist of our commercial paper program that provides an additional financing source for our short-term liquidity needs. Short-term borrowings increased $120.3 million, or 100.3 percent, to $240.2 million as of June 30, 2017 compared to $119.9 million as of December 31, 2016. The increase was due to additional issuances in June 2017 compared to December 2016.

Accrued property taxes decreased $10.6 million, or 38.4 percent, to $17.0 million as of June 30, 2017 compared to $27.6 million as of December 31, 2016. The decrease was due to $27.3 million of property tax payments during 2017 (of which $16.7 million were paid during the second quarter of 2017) partially offset by accruals for property taxes due in future periods. Also, accrued property taxes decreased during the second quarter of 2017 due to a favorable accrual adjustment of $2.5 million related to the current year Colorado property tax valuations.

Current maturities of long-term debt decreased $30.6 million, or 28.3 percent, to $77.3 million as of June 30, 2017 compared to $107.9 million as of December 31, 2016. The decrease was primarily due to a lower Springerville certificate debt payment due during the first quarter of 2018 of $25.6 million compared to the same period in 2017 and paying off the City of Gallup, NM pollution control revenue bonds of $5.5 million during the first quarter of 2017.

Regulatory liabilities decreased $22.8 million, or 23.9 percent, to $72.7 million as of June 30, 2017 compared to $95.5 million as of December 31, 2016. The decrease was due to the income recognition of $15.0 million of previously deferred 2011 and 2008 deferred non-member electric sales revenue and the income recognition of $5.0 million of previously deferred other income in connection with the June 30, 2016 withdrawal of KCEC from membership in us. Also, there was a decrease in the deferred unrealized gain related to the change in fair value of the interest rate swap of $2.8 million.

Other deferred credits decreased $16.7 million, or 25.2 percent, to $49.5 million as of June 30, 2017 compared to $66.2 million as of December 31, 2016. The decrease was primarily due to the January 12, 2017 settlement of the $15.5 million refund from TEP required by the Federal Energy Regulatory Commission for transmission service agreements that was recorded in other deferred credits in 2016. We returned $7.75 million to TEP and recognized $7.75 million that we retained as a reduction in transmission expense on our statement of operations during the first quarter of 2017.

Liquidity

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of debt. As of June 30, 2017, we had $139.4 million in cash and cash equivalents. Our committed credit arrangement as of June 30, 2017 is as follows (dollars in thousands):

	Authorized Amount	Available June 30, 2017
Revolving Credit Agreement	$ 750,000 (1)	$ 462,052 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.
(2) Of the portion of this facility that was unavailable at June 30, 2017, $47.7 million was related to a letter of credit issued to support variable rate demand bonds and $240.2 million was dedicated to support outstanding commercial paper.

The Revolving Credit Agreement has aggregate commitments of $750 million which includes a swingline sublimit of $100 million, a letter of credit sublimit of $200 million, and a commercial paper back-up sublimit of $500 million, of which $100 million of the swingline sublimit, $152 million of the letter of credit sublimit, and $259.8 million of the commercial paper back-up sublimit remained available as of June 30, 2017. 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 the Revolving Credit Agreement, which was $500 million at June 30, 2017, thereby providing 100 percent dedicated support for any commercial paper outstanding. We had $240.2 million of commercial paper outstanding at June 30, 2017.

The Revolving Credit Agreement is secured under the Master Indenture and has a term extending through July 26, 2019. We had no outstanding borrowings at June 30, 2017 and December 31, 2016 and an issued letter of credit for the Moffat County, CO pollution control revenue bonds in the principal amount of $46.8 million plus accrued interest supported by the Revolving Credit Agreement. Funds advanced under the Revolving Credit Agreement bear interest either at a Eurodollar rate or a base rate, at our option. The Eurodollar rate is the LIBOR rate for the term of the advance plus a margin (currently 1.00%) based on our credit ratings. The base rate is the highest of (a) the federal funds rate plus ½ of 1.00%, (b) the Bank of America prime rate, and (c) the one-month LIBOR rate plus 1.00% and plus a margin (currently 0%) based on our credit ratings. As of June 30, 2017, we have $462.1 million in availability (including $259.8 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

The Revolving Credit Agreement contains financial covenants, including 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.

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

Cash Flow

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

June 30, 2017 compared to June 30, 2016

Operating activities. Net cash provided by operating activities was $60.1 million for the six months ended June 30, 2017 compared to $132.2 million for the same period in 2016, a decrease of $72.1 million. The decrease in cash provided by operating activities was primarily due to lower net margins (excluding the $20.0 million recognition of deferred revenue) and receiving $37.0 million of net cash in 2016 related to the withdrawal of KCEC from membership in us. Cash was also impacted by an increase in purchased power expense of $12.6 million, the return of $7.75 million to TEP for the January 12, 2017 settlement agreement related to the time value refund we received in 2016 from TEP, and an increase in interest payments of $2.0 million and property tax payments of $1.5 million. These decreases of cash for the six months ended June 30, 2017 compared to the same period in 2016 were partially offset by an increase in cash collected from Member accounts receivable resulting from increased loads of $11.2 million.

Investing activities. Net cash used in investing activities was $97.8 million for the six months ended June 30, 2017 compared to $101.3 million for the same period in 2016, a decrease of $3.5 million. The decrease was primarily due to a reduction in advance payments to the operating agents of jointly owned facilities resulting from lower costs. This decrease was partially offset by higher capital expenditures in 2017 compared to 2016 for the development of the Collom mining pit at the Colowyo Mine and various generation and transmission improvements and system upgrades.

Financing activities. Net cash provided by financing activities was $11.2 million for the six months ended June 30, 2017 compared to net cash used in financing activities of $16.7 million for the same period in 2016, an increase of $27.8 million. The increase was primarily due to higher commercial paper issuances to fund our short-term liquidity needs.

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 for existing generating facilities and existing and new transmission facilities going forward depend on a variety of factors, including Member load growth, availability of necessary permits, regulatory changes, environmental requirements, current construction costs, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

The majority of our capital expenditures consist of additions to electric plant and equipment. Capital projects include 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, 2017, we had approximately $2.7 billion of debt outstanding secured on a parity basis under our Master Indenture. Our debt secured by the lien of the Master Indenture includes notes payable to National Rural Utilities Cooperative Finance Corporation and CoBank, ACB (with the exception of three unsecured notes), the First Mortgage Obligations, Series 2009C, the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, the First Mortgage Bonds, Series 2014E-1 and E-2, the First Mortgage Bonds, Series 2016A, the pollution control revenue bonds, and amounts outstanding, if any, under the Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under the Master Indenture. We have three unsecured notes totaling $46 million and the Springerville certificates totaling $419 million. The Springerville certificates are secured only by a mortgage and lien on Springerville Generating Station Unit 3 and the Springerville lease.

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 stations and the transmission system.

Coal Purchase Obligations. We have commitments to purchase coal for our generating stations under long-term contracts that expire between 2017 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.

Rating Triggers

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s Investors Services, “A (stable outlook)” by Standard & Poor’s Ratings Services, and “A (stable outlook)” by Fitch Rating Inc. Our current short-term ratings are “P-2” by Moody’s, “A-1” by Standard & Poor’s Ratings Services, and “F1” by Fitch.

The 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 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 power sales arrangements that are required to be accounted for as operating leases, 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 – Purchase Power Agreements Accounted for as Leases

We have a 10-year purchase power 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 since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have not been any 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, 2016.

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

Information required by this Item is contained in the Notes to Unaudited Consolidated Financial Statements within Part I of this Form 10-Q in Note 13 - Legal.

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 Micheal S. McInnes (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 Micheal S. McInnes (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 14, 2017

By: /s/ Micheal S. McInnes
Micheal S. McInnes
Chief Executive Officer

Date: August 14, 2017

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