UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2015

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. 333-203560

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

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. **Yes** ☒ **No** ☐

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 or a smaller reporting company. See definitions of ''large accelerated filer,'' ''accelerated filer,'' and ''smaller reporting 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** ☐

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.
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2015

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 (unaudited)
(dollars in thousands)

	September 30, 2015	December 31, 2014
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,414,256	$ 5,193,236
Construction work in progress	176,020	206,097
Total electric plant	5,590,276	5,399,333
Less allowances for depreciation and amortization	(2,214,237)	(2,129,173)
Net electric plant	3,376,039	3,270,160
Other plant	230,064	210,694
Accumulated depreciation and depletion	(69,741)	(58,117)
Net other plant	160,323	152,577
Total property, plant and equipment	3,536,362	3,422,737
Other assets and investments		
Investments in other associations	119,170	117,976
Investments in and advances to coal mines	17,264	15,016
Restricted cash and investments	4,931	39,376
Intangible assets	27,465	32,958
Other noncurrent assets	13,034	12,531
Total other assets and investments	181,864	217,857
Current assets		
Cash and cash equivalents	195,209	92,468
Restricted cash and investments	10,323	9,784
Deposits and advances	27,055	22,224
Accounts receivable—Members	94,044	105,723
Other accounts receivable	16,349	25,693
Coal inventory	69,843	40,673
Materials and supplies	84,201	80,069
Total current assets	497,024	376,634
Deferred charges		
Regulatory assets	416,109	426,043
Prepayment—NRECA Retirement and Security Plan	50,525	54,665
Other	179,672	178,454
Total deferred charges	646,306	659,162
Total assets	**$ 4,861,556**	**$ 4,676,390**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 983,381	$ 908,669
Accumulated other comprehensive income (loss)	(914)	(828)
Noncontrolling interest	108,855	109,302
Total equity	1,091,322	1,017,143
Long-term debt	3,290,824	3,165,960
Total capitalization	4,382,146	4,183,103
Current liabilities		
Member advances	9,442	14,576
Accounts payable	92,184	103,177
Accrued expenses	24,103	30,005
Accrued interest	49,082	32,517
Accrued property taxes	25,898	26,010
Current maturities of long-term debt	97,409	94,342
Total current liabilities	298,118	300,627
Deferred credits and other liabilities		
Regulatory liabilities	45,000	45,000
Deferred income tax liability	24,417	17,230
Intangible liabilities	6,850	9,424
Asset retirement obligations	58,655	53,754
Other	37,876	59,121
Total deferred credits and other liabilities	172,798	184,529
Accumulated postretirement benefit and postemployment obligations	8,494	8,131
Total equity and liabilities	**$ 4,861,556**	**$ 4,676,390**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Operating Revenues				
Member electric sales	$ 334,009	$ 319,671	$ 858,840	$ 840,539
Non-member electric sales	30,394	50,530	95,242	160,590
Other	23,699	26,278	68,324	71,836
	388,102	396,479	1,022,406	1,072,965
Operating expenses				
Purchased power	91,001	99,260	235,422	251,687
Fuel	65,586	80,665	162,430	224,967
Production	55,485	53,292	179,382	167,470
Transmission	39,851	37,476	114,922	110,103
General and administrative	5,421	6,435	17,044	19,725
Depreciation and amortization	38,371	34,275	109,317	96,360
Coal mining	7,096	9,477	23,039	30,922
Other	3,879	5,996	11,504	14,378
	306,690	326,876	853,060	915,612
Operating margins	**81,412**	**69,603**	**169,346**	**157,353**
Other income				
Interest Income	1,071	3,038	3,241	9,357
Capital credits from cooperatives	754	1,720	5,995	3,758
Other income	808	749	2,659	2,424
	2,633	5,507	11,895	15,539
Interest expense, net of amounts capitalized	35,846	34,986	106,919	105,617
Income taxes	—	—	—	—
Net margins including noncontrolling interest	48,199	40,124	74,322	67,275
Net loss attributable to noncontrolling interest	103	327	390	1,060
Net margins attributable to the Association	**$ 48,302**	**$ 40,451**	**$ 74,712**	**$ 68,335**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net margins including noncontrolling interest	$ 48,199	$ 40,124	$ 74,322	$ 67,275
Other comprehensive income (loss):				
Unrealized loss on securities available for sale	(89)	(18)	(112)	(2)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	9	(90)	26	(269)
Income tax expense related to components of other comprehensive loss	—	—	—	—
Other comprehensive income (loss)	(80)	(108)	(86)	(271)
Comprehensive income including noncontrolling interest	48,119	40,016	74,236	67,004
Net comprehensive loss attributable to noncontrolling interest	103	327	390	1,060
Comprehensive income attributable to the Association	**$ 48,222**	**$ 40,343**	**$ 74,626**	**$ 68,064**

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)

	Nine Months Ended September 30,	
	2015	2014
Patronage capital equity at beginning of period	$ 908,669	$ 865,379
Net margins attributable to the Association	74,712	68,335
Retirement of patronage capital	—	(10,000)
Patronage capital equity at end of period	**983,381**	**923,714**
Accumulated other comprehensive income (loss) at beginning of period	(828)	3,335
Unrealized loss on securities available for sale	(112)	(2)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	26	(269)
Accumulated other comprehensive income (loss) at end of period	**(914)**	**3,064**
Noncontrolling interest at beginning of period	109,302	110,740
Net loss attributable to noncontrolling interest	(390)	(1,060)
Equity distribution to noncontrolling interest	(57)	(55)
Noncontrolling interest at end of period	**108,855**	**109,625**
Total equity at end of period	**$ 1,091,322**	**$ 1,036,403**

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

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

	Nine Months Ended September 30,	
	2015	2014
Operating activities		
Net margins including noncontrolling interest	$ 74,322	$ 67,275
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation and amortization	109,317	94,341
Amortization of intangible asset	5,493	5,493
Amortization of NRECA Retirement and Security Plan prepayment	4,140	4,140
Amortization of debt issuance costs	1,400	696
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(3,698)	(1,136)
Recognition of deferred revenue	—	(15,000)
Change in restricted cash and investments	29,148	29,213
Changes in operating assets and liabilities:		
Accounts receivable	21,026	15,794
Coal inventory	(29,170)	13,462
Materials and supplies	(4,132)	(5,373)
Accounts payable and accrued expenses	(10,845)	(7,843)
Accrued interest	16,565	895
Accrued property taxes	(112)	2,531
Other deferred credits - BNSF settlement	(29,381)	—
Other	11,084	4,260
Net cash provided by operating activities	**195,157**	**208,748**
Investing activities		
Purchases of plant	(217,929)	(157,526)
Changes in deferred charges	1,495	(5,652)
Proceeds from other investments	407	6,498
Net cash used in investing activities	**(216,027)**	**(156,680)**
Financing activities		
Member advances	(5,134)	1,436
Payments of long-term debt	(101,772)	(273,275)
Proceeds from issuance of debt	230,185	79,676
Decrease in advance payments to RUS	—	38,908
Retirement of patronage capital	(4,213)	(13,849)
Change in restricted cash and investments	323	48,000
Proceeds from investment in securities pledged as collateral	4,222	4,526
Net cash provided by (used in) financing activities	**123,611**	**(114,578)**
Net increase (decrease) in cash and cash equivalents	**102,741**	**(62,510)**
Cash and cash equivalents – beginning	**92,468**	**193,057**
Cash and cash equivalents – ending	**$ 195,209**	**$ 130,547**
Supplemental cash flow information:		
Cash paid for interest	$ 101,480	$ 100,303
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (1,152)	$ (769)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements
For the Three and Nine Months Ended September 30, 2015 and 2014

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 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 U.S. generally accepted accounting principles ("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 2014 Annual Report in our Registration Statement on Form S-4 (Registration No. 333-203560) that was declared effective by the SEC on July 29, 2015. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the three and nine months ended September 30, 2015 and 2014 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., our wholly-owned and majority-owned subsidiaries and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries (see Note 10 – 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 ("BEPC")) 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 operating expenses is included in our consolidated financial statements.

Our share in each jointly owned facility is as follows as of September 30, 2015 (thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Station Units 1 and 2	24 %	$ 345,409	$ 228,607	$ 19,398
MBPP - Laramie River Station	24.13 %	391,790	290,879	8,504
San Juan Project – San Juan Unit 3	8.2 %	84,103	59,435	141
Total		$ 821,302	$ 578,921	$ 28,043

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, 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 Members through rates approved by our Board of

Directors 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 of Directors in accordance with our rate policy.

Regulatory assets and liabilities are as follows (thousands):

	September 30, 2015	December 31, 2014
Regulatory assets		
Deferred income tax expense (1)	$ 24,417	$ 17,230
Deferred prepaid lease expense- Craig 3 Lease (2)	17,802	22,656
Deferred prepaid lease expense- Springerville 3 Lease (3)	93,450	95,168
Goodwill – J.M. Shafer (4)	61,253	63,390
Goodwill – Colowyo Coal (5)	41,585	43,526
Deferred debt prepayment transaction costs (6)	177,602	184,073
	416,109	426,043
Regulatory liabilities		
Deferred revenues (7)	45,000	45,000
Net regulatory asset	$ 371,109	$ 381,043

(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 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 and amortization expense in the amount of $6.5 million annually through the remaining original life of the lease ending in 2018 and recovered from our Members in rates.
(3) Deferral of loss on acquisition related to the Springerville Generating Station 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 and amortization 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 in December 2011. Goodwill is being amortized to depreciation and amortization 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 and amortization expense 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 and amortization 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 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. These deferred non-member electric sales revenues will be refunded to Members through reduced rates when recognized in non-member electric sales revenue in future periods.

NOTE 3 – INVESTMENTS IN OTHER ASSOCIATIONS

Investments in other associations include our investment in the patronage capital of other cooperatives and these investments are typically accounted for using the cost method. 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. Investments in cooperatives where we have significant influence over operating and financial policy are accounted for using the equity method. 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 of Directors for specific uses and funds restricted by contract or other legal reasons. A portion of the funds is for the payment of debt within one year and is therefore a current asset on the statements of financial position. The other funds are noncurrent and are included in other assets and investments.

We have investments in U.S. Treasury Notes pledged as collateral in connection with the in-substance defeasance for the principal outstanding and future interest payments on the Coal Contract Receivable Collateralized Bonds ("Colowyo Bonds"). The balances in these investments are described as investments in securities pledged as collateral in the table below. A portion of the defeasance investment is for Colowyo Bond debt payments within one year and is, therefore, a current asset on the consolidated statements of financial position. The remainder of the investment is noncurrent.

We received $29.4 million in 2009 from the BNSF Railway Company ("BNSF") as a reduction of prior coal delivery shipping charges as the result of the decision of the Surface Transportation Board ("STB"). However, BNSF appealed the decision and the funds were subject to refund in the event BNSF was ultimately successful in its appeal. These funds were designated by our Board of Directors to be held as restricted cash. In May 2015, BNSF, Western Fuels Association ("WFA") and BEPC filed a joint petition at the STB informing the STB that the parties had entered into a rail transportation agreement settling all matters at issue. In June 2015, the STB granted the joint petition, which resolved the uncertainties related to the outcome of this matter and the $29.4 million of cash related to the BNSF settlement was no longer designated as restricted.

Restricted cash and investments are as follows (thousands):

	September 30, 2015	December 31, 2014
Investments in securities pledged as collateral	$ 9,498	$ 9,192
Funds restricted by contract	825	592
Restricted cash and investments - current	10,323	9,784
BNSF settlement	—	29,381
Funds restricted by contract	1,000	1,000
Investments in securities pledged as collateral	3,931	8,995
Restricted cash and investments - noncurrent	4,931	39,376
Total restricted cash and investments	$ 15,254	$ 49,160

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 may 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 of Directors, which has budgetary and rate-setting authority. As of September 30, 2015, preliminary surveys and investigations was primarily comprised of expenditures for the Holcomb Station Project of $85.5 million and $28.2 million for a transmission project located in eastern Colorado ("Eastern Plains Transmission Project").

We make advance payments to the operating agents of jointly owned facilities.

We account for debt issuance costs as deferred debt expense. Deferred debt expense is amortized to interest expense, net of amounts capitalized using an effective interest method over the life of the respective debt issuance. As of September 30, 2015, the remaining amortization periods for debt issuance costs range from approximately 2 to 34 years.

Other deferred charges are as follows (thousands):

	September 30, 2015	December 31, 2014
Preliminary surveys and investigations	$ 136,667	$ 131,693
Advances to operating agents of jointly owned facilities	19,072	20,567
Debt issuance costs	21,669	22,254
Other	2,264	3,940
Total other deferred charges	$ 179,672	$ 178,454

NOTE 6 – LONG-TERM DEBT

The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement except for one unsecured note. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Generating Station Unit 3. The Colowyo Bonds are secured by funds deposited with the trustee as part of the in-substance defeasance and an unconditional guarantee by us. All long-term debt contains certain restrictive financial covenants, including a debt service ratio requirement and an 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 ("2011 Credit Agreement"). We had outstanding borrowings of $261 million and $50 million at September 30, 2015 and December 31, 2014, respectively, and an issued letter of credit in the principal amount of $46.8 million plus accrued interest supported by the 2011 Credit Agreement. As of September 30, 2015, we have $441 million in availability under the 2011 Credit Agreement.

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

	September 30, 2015	December 31, 2014
Total debt	$ 3,388,233	$ 3,260,302
Less current maturities	(97,409)	(94,342)
Long-term debt	$ 3,290,824	$ 3,165,960

NOTE 7 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES

We received $29.4 million in 2009 from BNSF as a reduction of prior coal delivery shipping charges as the result of the decision of the STB. However, BNSF appealed the decision and the funds were subject to refund in the event BNSF was ultimately successful in its appeal. Due to uncertainties regarding the ultimate outcome of this matter, we did not recognize the benefit of the receipt of the $29.4 million in 2009. In May 2015, BNSF, WFA, and BEPC filed a joint petition at the STB informing the STB that the parties had entered into a rail transportation agreement settling all matters at issue. In June 2015, the STB granted the joint petition, which resolved the uncertainties related to the outcome of this matter. Therefore, pursuant to the BNSF rate settlement, $24.4 million was recognized in June 2015 as a reduction to fuel expense.

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. 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.

Other deferred credits and other liabilities are as follows (thousands):

	September 30, 2015	December 31, 2014
BNSF rate settlement proceeds not recognized in income	$ —	$ 29,381
Customer deposits	6,166	2,464
Unearned revenue	4,726	4,210
Other deferred credits	26,984	23,066
Total other deferred credits and other liabilities	$ 37,876	$ 59,121

NOTE 8 – 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 no income tax expense or benefit for the three and nine months ended September 30, 2015 and 2014.

NOTE 9 – 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 measurements accounting guidance emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability (market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress). In considering market participant assumptions in fair value measurements, a three-tier fair value hierarchy for measuring fair value was established which prioritizes the inputs used in measuring fair value as follows:

Level 1 inputs utilize observable market data in active markets for identical assets or liabilities.

Level 2 inputs consist of observable market data, other than that included in Level 1, that is either directly or indirectly observable.

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 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. Changes in the net unrealized gains or losses are reported as a component of comprehensive income. The carrying amounts and fair values of our marketable securities are as follows (thousands):

	As of September 30, 2015		As of December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Marketable securities	$ 939	$ 1,081	$ 1,095	$ 1,349

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 at September 30, 2015 and December 31, 2014 are reported as a component of accumulated other comprehensive income as of those dates. Changes in the net unrealized gains or losses are reported as a component of comprehensive income.

Long-Term Debt

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

The carrying amounts and fair values of our long-term debt are as follows (thousands):

	As of September 30, 2015		As of December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$ 3,388,233	$ 3,719,615	$ 3,260,302	$ 3,716,513

We did not have any financial assets or liabilities measured at fair value on a recurring basis that are included in the Level 3 fair value category.

NOTE 10 – 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”) of the Springerville Generating Station Unit 3. We, as general partner, 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 Generating Station 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 Generating Station Unit 3 assets and are responsible for 100 percent of the operation, maintenance and capital expenditures of Springerville Generating Station 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 $858.6 and $874.4 million at September 30, 2015 and December 31, 2014, respectively, the long-term debt of $511.6 and $548.1 million at September 30, 2015 and December 31, 2014, respectively, accrued interest associated with the long-term debt of $5.7 million and $15.2 million at September 30, 2015 and December 31, 2014, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $108.9 and $109.3 million at September 30, 2015 and December 31, 2014, respectively.

Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $5.3 million for the three months ended September 30, 2015 and the comparable period in 2014. Our consolidated statements of operations also include interest expense of $8.0 million for the three months ended September 30, 2015 and $8.5 million for the comparable period in 2014. Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $15.8 million for the nine months ended September 30, 2015 and the comparable period in 2014. Our consolidated statements of operations also include interest expense of $24.3 million for the nine months ended September 30, 2015 and $25.6 million for the comparable period in 2014. The net losses attributable to the 49 percent noncontrolling equity interest in the Springerville Partnership are 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 ("WFA"): WFA is a not-for-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 Generating Station 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 September 30, 2015 and $2.3 million at December 31, 2014, respectively, 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 BEPC). 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 (the owners of the Craig Generating Station Units 1 and 2). 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 $15.5 million at September 30, 2015 and $13.7 million at December 31, 2014.

NOTE 11 – LEGAL

In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five days in northern New Mexico, primarily on national forest service land in the Santa Fe National Forest. Six plaintiff groups, comprised 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 the right of way fell onto a distribution line owned by JMEC as a result of high winds. On January 7, 2014, the court allowed all parties and related parties to amend their complaints to include the addition of us as a party defendant. These cases are State Farm Fire and Casualty Company, et. al. v. Jemez Mountains Electric Cooperative, Inc., et. al. (amended complaint filed March 6, 2014); Elizabeth Ora Cox, et. al., v. Jemez Mountains Electric Cooperative, Inc., et. al. (second amended complaint filed January 31, 2014); Norman Armijo, et. al., v. Jemez Mountains Electric Cooperative, Inc., et al. (amended complaint filed January 16, 2014); United Services Automobile Association, et. al. v. Jemez Mountains Electric Cooperative, Inc. (amended complaint filed March 6, 2014); Jemez Pueblo v. Jemez Mountains Electric Cooperative, Inc., et. al. (filed June 10, 2013); and Pueblo De Cochiti., et. al. v. Jemez Mountains Electric Cooperative, Inc., et. al. (filed June 10, 2013). The allegations in each case are similar. Plaintiffs allege that we owed them independent duties to inspect and maintain the right-of-way for JMEC's distribution line and that we are also jointly liable for any negligence by JMEC under joint venture and alter ego theories. On June 16, 2014, we filed multiple motions for summary judgment including for plaintiffs' claims related to nuisance, trespass, negligence per se, independent duty, joint venture and alter ego. On December 29, 2014, we received a demand letter from the U.S. Department of Justice for costs incurred as a result of the fire, also alleging the joint venture theory. JMEC has settled with the subrogated insurers, executing and funding the deal on December 30, 2014 and on February 7, 2015, the court dismissed the subrogated insurers' claims against us with prejudice. Settlement demands have been received from plaintiffs Jemez Pueblo and Pueblo de Cochiti claiming damages in the amount of approximately $34.4 million and $23.9 million, respectively, focusing mainly on damages arising from flooding subsequent to the fire. On March 9, 2015, the court granted our motions for summary judgment related to nuisance, trespass, negligence per se, and alter ego, but denied our motions related to independent duty and joint venture. On March 17, 2015, we filed an application for interlocutory appeal with the New Mexico Court of Appeals related to the district court's denial of our motions for summary judgment for plaintiffs' claims related to independent duty and joint venture. The New Mexico Court of Appeals denied our application for interlocutory appeal on May 27, 2015. A jury trial commenced on September 28, 2015. 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 found JMEC was 75 percent negligent, Tri-State was 20 percent negligent, and the United States Forest Service was 5 percent negligent, and each had a role in causing the fire. We are evaluating our options regarding an appeal of the case. A separate trial will occur at a later date to determine the amount of damages. We maintain $100 million in liability insurance coverage for this matter. Although we cannot predict the outcome of these matters 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.

On February 9, 2015, Delta-Montrose Electric Association (''DMEA'') filed a Petition For Declaratory Order with the United States Federal Energy Regulatory Commission (''FERC'') seeking a declaratory order from FERC finding that its wholesale electric service contract with us is subject to FERC jurisdiction because we have paid off all our Rural Utilities Service debt; that the wholesale electric service contract cannot be read to preclude DMEA from purchasing power from a ''qualifying facility,'' which is a co-generator or renewable small power producer capable of producing up to 80 MW, pursuant to the provisions of PURPA and FERC regulations thereunder; and that DMEA has the right under

FERC’s PURPA regulations to negotiate its purchase power price from a ‘‘qualifying facility’’ and to reduce its purchases from us by that amount even if that amount exceeds its contractual obligation to purchase from us. We filed our motion to intervene and protest with FERC related to such petition on March 11, 2015. DMEA filed a motion to answer and answer to our protest on March 26, 2015. We filed a motion for leave to answer and answer to DMEA’s answer on April 2, 2015. On June 18, 2015, FERC issued an order stating (a) DMEA is obligated to purchase from “qualifying facilities” offering available energy and capacity and such sales may be at negotiated rates and (b) we are not subject to the general FERC rate jurisdiction under the Federal Powers Act (“FPA”). On July 20, 2015, Kit Carson Electric Cooperative, Inc. (“Kit Carson”) filed a Motion for Clarification or Alternatively, Rehearing with FERC seeking a clarification of the FERC order, or alternatively, a rehearing, to the extent the FERC order applies to any of our policies or the application of any of our policies regarding Kit Carson’s obligations under PURPA to purchase renewable energy from a “qualifying facility” and as it relates to Kit Carson’s obligation to purchase and receive at least 95 percent of its electric power requirements from us under the wholesale electric service contract. On August 3, 2015, we filed a motion for leave to answer and answer to Kit Carson’s motion requesting FERC to deny Kit Carson’s motion because it is beyond the scope of FERC’s order in the proceeding and not within FERC’s jurisdiction under the FPA. On October 15, 2015, FERC denied Kit Carson’s Motion for Clarification or Alternatively, Rehearing stating FERC’s earlier order does not need further clarification and further restating that DMEA was obligated to purchase power from any “qualifying facility” that can deliver its power to DMEA regardless of any conflicting contract terms found in the wholesale electric service contract. We do not expect the FERC order or the denial of Kit Carson’s motion to have a material adverse effect on our financial condition or our future results of operations or cash flows. We are evaluating our options regarding its impact on our wholesale electric service contracts with our Members.

In February 2013, WildEarth Guardians (‘‘WEG’’) filed suit against the United States Office of Surface Mining, Reclamation and Enforcement (‘‘OSM’’), in the United States District Court for the District of Colorado, alleging OSM’s failure to involve the public and address the economic impacts of coal mining throughout the Rocky Mountain West prior to mine plan approval. The suit alleged unlawful mine plan approval of mines located in Colorado, Montana, New Mexico, and Wyoming. The court granted intervention to several mine owners, including Colowyo Coal and Trapper Mining. The Colowyo Mine plan in WEG’s suit was approved in 2007 and the Trapper Mine plan in WEG’s suit was approved in 2009. In February 2014, the court agreed to sever the claims and transfer venue for the mines located outside of Colorado. In August 2014, WEG submitted its opening brief on the part of the case that remained in Colorado as Civil Action No. 1:13-cv-00518-RBJ. OSM’s responsive brief was filed on October 7, 2014, and Trapper Mining and Colowyo Coal, as intervenors, each filed a responsive brief on October 20, 2014. WEG asked the court to declare that OSM’s approval of the mine plans violated the National Environmental Policy Act (‘‘NEPA’’) and for the court to vacate the approvals until OSM demonstrates compliance with the act. Oral arguments took place on April 24, 2015. On May 8, 2015, the court issued an order agreeing with WEG that OSM’s approval of the mine plans violated NEPA. The court noted that the majority of the coal covered by the permit at Trapper Mine had already been mined, but ordered that no remaining coal covered by the permit be mined prior to approval of a new permit revision. With respect to the Colowyo Mine, the court determined that immediate vacatur of the Colowyo Mine plan did not outweigh the potential harm. The court deferred an immediate vacatur order for a period of 120 days from May 8, 2015 and expected the OSM during that time to address the deficiencies in the permitting process. On May 29, 2015, Colowyo Coal filed a Notice of Appeal and Motion to Stay the Order issued by the court. On July 25, 2015, the court denied Colowyo Coal’s Motion to Stay the Order. On July 27, 2015, OSM released a draft remedial environmental assessment of Colowyo Coal’s mining permit modification with a preliminary Finding of No Significant Impact. On August 31, 2015, OSM signed an environmental assessment of Colowyo Coal’s mine permit modification with a Finding of No Significant Impact, which was approved by the Assistant Secretary on September 2, 2015. On September 4, 2015, OSM filed a Notice of Compliance stating OSM had complied with the court’s May 8, 2015 order, thus obviating the need for entry of a vacatur order.

NOTE 12 – NEW ACCOUNTING PRONOUNCEMENTS

In February 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2015-02, *Consolidation (Topic 810), Amendments to the Consolidation Analysis*. The amendments in this ASU affect reporting entities that are required to evaluate whether they should consolidate certain legal entities. All legal entities are subject to reevaluation under the revised consolidation model. Specifically, ASU 2015-02: (1) modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities, (2) eliminates the presumption that a general partner should consolidate a limited partnership, and (3) affects the consolidation analysis of reporting entities that are involved with variable interest entities, particularly those that have fee arrangements and related party relationships. For public business entities, ASU 2015-02 is effective for the fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted, including adoption in an interim period. A reporting entity may apply the amendments in this ASU using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption. A reporting entity also may apply the amendments retrospectively. The adoption of this amendment is not expected to have a material impact on our financial position and results of operations.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606).* Subsequently, FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. ASU 2014-09 replaces current revenue guidance, which was based on a risks and rewards model, with a transfer of control model. The core principle under the new transfer of control model states 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, this amendment requires the following steps: (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 additional quantitative and qualitative disclosures sufficient enough to enable users of financial information to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, 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). Reporting entities have the option to adopt the standard as early as the original January 1, 2017 effective date of this amendment. We are currently evaluating the impact of this amendment 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 incorporated in 1952 and operating on a not-for-profit basis. We are organized for the purpose of providing electricity to our 44 member distribution systems, or Members, that serve major parts of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our generated electric power to other utilities in the region pursuant to long-term contracts and spot 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. In 2014, our Members served approximately 614,000 retail electric meters over a 200,000 square-mile area with a population of approximately 1.5 million people. We sold 13.7 million MWhs for the nine months ended September 30, 2015, of which 87 percent was to Members. Total revenue from electric sales was $954.1 million for the nine months ended September 30, 2015, of which 90 percent was from Member sales.

We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members and extending through 2040 for the remaining two Members, and subject to automatic extension thereafter until either party provides at least a two year 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 September 30, 2015, 16 Members have enrolled in this program with capacity totaling approximately 72 MWs.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating stations, long-term purchase contracts, and forward, short-term and spot market 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.

Summary of Significant Accounting Policies

As of September 30, 2015, there have been no material changes in our significant accounting policies as disclosed in our 2014 notes to consolidated financial statements.

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 Financial Goals and Capital Credits Policy, approved and subject to change by our Board of Directors, 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 of Directors evaluates liquidity goals and equity goals (that are a part of the Financial Goals and Capital Credits Policy) in determining the timing and amount of patronage capital retirement, and if the Board of Directors determines that our financial condition will not be impaired, a portion of retained patronage capital may be retired. Historically, patronage capital has been retired in order of priority according to the year in which the patronage capital was furnished and credited; however, our bylaws were recently amended to provide the Board of Directors' discretion on order of retirement. As of September 30, 2015, patronage capital equity is $983.4 million. To date, we have retired approximately $303 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 a demand rate. Member rates for energy and demand are set by our Board of Directors, consistent with adequate electrical reliability and sound fiscal policy. Energy is the physical electricity delivered through the transmission system to our Members. In 2012, our rate schedule (A-36 rate) had an energy rate billed based upon a price per kWh of energy delivered and a demand rate based upon our Member's highest thirty-minute integrated total demand measured using actual metered kilowatt usage in each monthly billing period during our summer peak period or the winter peak period. Beginning January 1, 2013, we implemented a rate design (A-37 rate) that incorporates seasonal average demand rates. The monthly average demand is calculated by dividing each Member's total monthly energy (kWh) usage by the total hours in the month. The A-37 rate design also had an energy rate that incorporates an on-peak and off-peak period. We developed demand response and energy shaping products to compliment the A-37 rate schedule. The participating Member's monthly statements were adjusted using the demand response and energy shaping product incentives for Members utilizing those products. Beginning January 1, 2014, the A-38 rate design went into effect. The only change from the A-37 rate design was to implement a slight increase in the seasonal average demand rates. In November 2014, we implemented an optional rate (TR-1) available to our non-New Mexico Members, effective December 1, 2014 through December 31, 2015. The TR-1 optional rate has an energy rate billed based upon a price per kWh of energy delivered and a demand rate based upon our Member's highest thirty-minute integrated total demand measured using the Member's coincident peak during our peak period in each monthly billing period during our summer peak period or the winter peak period. As of September 30, 2015, three Members have elected this TR-1 optional rate. Approved by our Board of Directors in September 2015 and effective January 1, 2016, we will be implementing a new rate design (A-39 rate) in which demand will be 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 Friday, with the exception of six holidays. Energy will be billed based upon a price per kWh of energy.

Although rates established by our Board of Directors 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. We are also involved in proceedings pending in New Mexico and Colorado regarding efforts by the NMPRC and the Colorado Public Utilities Commission, or COPUC, related to our wholesale rates payable by our Members.

As required by New Mexico law, we file our rates to our New Mexico Members with the NMPRC, which has regulatory authority over rate increases in New Mexico, only in the event three or more of our New Mexico Members file a request for such a review and such review is found to be qualified by the NMPRC. In November 2012, three of our New Mexico Members filed protests with the NMPRC of the A-37 rate that we filed with the NMPRC on October 19, 2012 and which was scheduled to become effective on January 1, 2013. The A-37 rate would have increased revenue collected from our 44 Members by approximately 4.9 percent and from our 12 New Mexico Members by approximately 6.7 percent. On December 20, 2012, the NMPRC suspended the A-37 rate filing in New Mexico and appointed a hearing examiner to conduct a hearing and establish reasonable rate schedules pursuant to New Mexico law. In June 2013, we attempted to withdraw the A-37 rate notice in New Mexico because our development and implementation of the 2014 rate would likely be completed prior to NMPRC action on the suspended A-37 rate. The NMPRC suspended consideration of the A-37 rate but did not permit the withdrawal of the rate. On September 10, 2013, we gave notice, as required by New Mexico law, to the NMPRC of our 2014 wholesale rate which was scheduled to become effective on January 1, 2014, or the A-38 rate. Four Members filed protests with the NMPRC challenging the A-38 rate. The A-38 rate modified the rate design but did not increase the general revenue requirement. On December 11, 2013, the NMPRC suspended the A-38 rate filing and assigned the consolidated A-37 and A-38 rate filings to a hearing examiner. In August 2014, we and the New Mexico Members executed a preliminary mediation agreement providing for a temporary rate rider through no later than December 31, 2015 (unless terminated earlier as provided in the preliminary mediation agreement) and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. We filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider (NM-X-38) is applied in conjunction with the 2012 wholesale rate (A-36) to recover additional revenue from the New Mexico Members in an annualized amount of $7 million per year, which was prorated beginning October 2 for 2014. The overall impact of the New Mexico Members paying a lower rate was $5.0 and $10.0 million for the three and nine months ended September 30, 2015, respectively. On October 9, 2015, we gave notice, as required by New Mexico law, to the NMPRC of our 2016 wholesale rate which is scheduled to become effective on January 1, 2016, or the A-39 rate. No New Mexico Member filed a protest with the NMPRC of the A-39 rate and thus the A-39 rate will become effective on January 1, 2016 without NMPRC review or approval.

On March 4, 2013, three of our Colorado Members and several of their large industrial customers filed a complaint at the COPUC alleging that the A-37 rate design was unjust and unreasonable. On April 4, 2013, we filed a motion to dismiss the complaint arguing lack of jurisdiction by the COPUC over our wholesale rates. The COPUC assigned the matter to an administrative law judge. The judge bifurcated the case into deciding first, whether the COPUC had the jurisdiction to hear such a case against us, who has been historically regulated by its membership through its Board of Directors, and secondly to hear the facts in the case depending on jurisdiction. The administrative law judge conducted a hearing in July 2013 and ruled on September 11, 2013 denying our motion to dismiss. In October 2013, we appealed the administrative law judge's decision to the full commission and on December 18, 2013, the commission granted in part and denied in part our motion contesting the administrative law judge's decision and remanded the case to the administrative law judge to hold a hearing on limited issues. In November 2014, we and the three Colorado Members executed a preliminary agreement providing for a temporary optional rate (TR-1 rate) effective December 1, 2014 and to continue through no later than December 31, 2015, available to all non-New Mexico Members and a suspension of the procedural schedule related to the complaint. The administrative law judge entered a decision on November 28, 2014 holding this matter in abeyance until December 31, 2015 to give the parties time to work toward a global settlement and permanent rate.

Master Indenture

As of September 30, 2015, we had approximately $2.8 billion of secured indebtedness outstanding under the Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under the Master Indenture. The Master Indenture requires us to establish rates annually that are designed to maintain 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 historic and pro forma basis. The Master Indenture also requires us to maintain an Equity to Capitalization Ratio (as defined in the Master Indenture), or ECR, at the end of each fiscal year of 14 percent through 2015, and 18 percent thereafter.

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 operating revenues fluctuate from period to period based on several factors, including fuel costs, weather, seasonal factors, load requirements in our Members' service territories, operating costs, availability of generating stations, and our decision whether to dispatch our own resources or make spot market energy purchases.

We currently anticipate that continued growth in our Members' energy requirements will occur. Much of this growth is related to the large commercial sector, due to increased natural gas, crude oil, and carbon dioxide extraction, processing and transportation. We forecast that our Member load will grow at an average of approximately 2.0 to 3.0 percent annually over the next five years.

Three months ended September 30, 2015 compared to three months ended September 30, 2014

Operating Revenues

Member electric sales increased 188,466 MWhs, or 4.3 percent, to 4,535,820 MWhs for the three months ended September 30, 2015 compared to 4,347,354 MWhs for the same period in 2014. The increase in MWhs sold in 2015 resulted in an increase of $14.3 million, or 4.5 percent, in Member electric sales revenue to $334.0 million for the three months ended September 30, 2015 compared to $319.7 million for the same period in 2014. The increase in revenue was primarily due to an increase in oil and gas loads and higher seasonal irrigation loads.

Non-member electric sales decreased 237,159 MWhs, or 27.3 percent, to 631,687 MWhs for the three months ended September 30, 2015 compared to 868,846 MWhs for the same period in 2014. Non-member electric sales revenue decreased $20.1 million, or 39.9 percent, to $30.4 million for the three months ended September 30, 2015 compared to $50.5 million for the same period in 2014. The decrease in non-member electric sales revenue was largely due to a decrease in long-term firm energy sales to non-members of 233,073 MWhs with revenues of $14.1 million and a decrease in spot market sales of 4,086 MWhs with revenues of $1.0 million. The decrease in long-term firm energy sales to non-members was primarily due to the expiration of power sales arrangements on February 1, 2015 and September 30, 2014 that were not renewed resulting in a decrease in non-member electric sales revenue of $12.4 million for the three months ended September 30, 2015 compared to the same period in 2014. When a power generating station is initially placed into service, there is generally a period of time when sales from such stations are not needed to serve our Members. In such cases, we may enter into contracts with non-members, which provide revenue to us during such periods and reduce the Member revenue requirements. We generally try to time the expiration of these contracts to coincide with forecasted increased Member demand, which has the effect of reducing non-member sales following such expirations. As a result, we determined not to renew the agreements upon their expiration. The decrease in spot market sales revenue was due to the 4,086 MWh decrease in MWhs sold and lower market prices for the three months ended September 30, 2015 compared to the same period in 2014. Additionally, there was a $5.0 million decrease in non-member electric sales revenue due to the recognition in the three months ended September 30, 2014 of $5.0 million of regulatory liabilities previously recorded for deferred non-member electric sales revenue and there being no such recognition in the three months ended September 30, 2015. The recognition in 2014 resulted in reduced Member revenue requirements (lower Member rates) as was required in 2014 by our Board of Directors in accordance with its budgetary and rate-setting authority.

Operating Expenses

Purchased power decreased 107,808 MWhs, or 5.1 percent, to 1,999,444 MWhs for the three months ended September 30, 2015 compared to 2,107,252 MWhs for the same period in 2014. Purchased power expense decreased $8.3 million, or 8.3 percent, to $91.0 million for the three months ended September 30, 2015 compared to $99.3 million for the same period in 2014 due to the decrease in MWhs purchased and a 4.5 percent decrease in the average cost per MWh of purchased power resulting from lower market prices for power.

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense decreased $15.1 million, or 18.7 percent, to $65.6 million for the three months ended September 30, 2015 compared to $80.7 million for the same period in 2014. The decrease in expense was primarily due to lower coal expense at our Craig Generating Station due to the lower cost per ton of coal provided by the Colowyo Mine during this period resulting from the increase in coal production at the Colowyo Mine in 2015.

Other Income

Interest income decreased $1.9 million, or 65.0 percent, to $1.1 million for the three months ended September 30, 2015 compared to $3.0 million for the same period in 2014. The decrease in interest income was primarily due to there being no investment during 2015 in the United States Department of Agriculture's Rural Utilities Service, or RUS, cushion of credit, which earned a 5 percent return. The investment in the RUS cushion of credit was eliminated by the 2014 debt refinancing (completed fourth quarter 2014) when our RUS debt and Federal Financing Bank debt was entirely paid off.

Nine months ended September 30, 2015 compared to nine months ended September 30, 2014

Operating Revenues

Member electric sales increased 300,310 MWhs, or 2.6 percent, to 11,944,526 MWhs for the nine months ended September 30, 2015 compared to 11,644,216 MWhs for the same period in 2014. The increase in MWhs sold in 2015 resulted in an increase of $18.3 million, or 2.2 percent, in Member electric sales revenue to $858.8 million for the nine months ended September 30, 2015 compared to $840.5 million for the same period in 2014. The increase in revenue was primarily due to an increase in oil and gas loads and higher seasonal irrigation loads.

Non-member electric sales decreased 969,934 MWhs, or 35.4 percent, to 1,769,099 MWhs for the nine months ended September 30, 2015 compared to 2,739,033 MWhs for the same period in 2014. Non-member electric sales revenue decreased $65.4 million, or 40.7 percent, to $95.2 million for the nine months ended September 30, 2015 compared to $160.6 million for the same period in 2014. The decrease in non-member electric sales revenue was primarily due to a decrease in long-term firm energy sales to non-members of 747,086 MWhs with revenue of $38.3 million and a decrease in spot market sales of 222,848 MWhs with revenues of $12.1 million. The decrease in long-term firm energy sales to non-members was primarily due to the expiration of power sales arrangements on February 1, 2015 and September 30, 2014 that were not renewed resulting in a decrease in non-member electric sales revenue of $36.1 million for the nine months ended September 30, 2015 compared to the same period in 2014. When a power generating station is initially placed into service, there is generally a period of time when sales from such stations are not needed to serve our Members. In such cases, we may enter into contracts with non-members, which provide revenue to us during such periods and reduce the Member revenue requirements. We generally try to time the expiration of these contracts to coincide with forecasted increased Member demand, which has the effect of reducing non-member sales following such expirations. As a result, we determined not to renew the agreements upon their expiration. The decrease in spot market sales revenue was due to the 222,848 MWh decrease in MWhs sold and lower market prices for the nine months ended September 30, 2015 compared to the same period in 2014. Additionally, there was a $15.0 million decrease in non-member electric sales revenue due to the recognition in the nine months ended September 30, 2014 of $15.0 million of regulatory liabilities previously recorded for deferred non-member electric sales revenue and there being no such recognition in the nine months ended September 30, 2015. The recognition in 2014 resulted in reduced Member revenue requirements (lower Member rates) as was required in 2014 by our Board of Directors in accordance with its budgetary and rate-setting authority.

Operating Expenses

Purchased power decreased 94,059 MWhs, or 1.8 percent, to 5,268,734 MWhs for the nine months ended September 30, 2015 compared to 5,362,793 MWhs for the same period in 2014. Purchased power expense decreased $16.3 million, or 6.5 percent, to $235.4 million for the nine months ended September 30, 2015 compared to $251.7 million for the same period in 2014 due to the decrease in MWhs purchased and a 5.4 percent decrease in the average cost per MWh of purchased power due to lower market prices for power.

Fuel expense decreased $62.6 million, or 27.8 percent, to $162.4 million for the nine months ended September 30, 2015 compared to $225.0 million for the same period in 2014. The decrease in expense was primarily due to the one-time $24.4 million reduction in fuel expense resulting from the BNSF rail transportation settlement and reduced coal consumption due to a decrease in generation of 620,649 MWhs, or 6.4 percent, for the nine months ended September 30, 2015 compared to the same period in 2014. The largest generation decreases were for Craig Generating Station Unit 3 and Laramie River Station due to scheduled maintenance outages in 2015.

Production expense includes the operation costs for the generating stations and generation maintenance expenses for maintaining the generating stations, such as costs of scheduled maintenance outages. Production expense increased $11.9 million, or 7.1 percent, to $179.4 million for the nine months ended September 30, 2015 compared to

$167.5 million for the same period in 2014. The increase in expense was primarily due to an increase in generation maintenance expenses resulting from scheduled maintenance outages at our Craig Generating Station and Laramie River Station.

Depreciation and amortization expense increased $12.9 million, or 13.4 percent, to $109.3 million for the nine months ended September 30, 2015 compared to $96.4 million for the same period in 2014. The increase in expense was primarily due to additions of equipment throughout our transmission system and at our generating stations. Additionally, amortization expense increased $6.5 million in 2015 resulting from the amortization of transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized over the 21.4-year average life of the new debt issued and recovered from our Members in rates.

Coal mining expense includes the Colowyo Mine operating expenses related to the portion of the coal sold from the Colowyo Mine to other joint owners in the Yampa Project pursuant to a contract expiring in 2017. Coal mining expense decreased $7.9 million, or 25.5 percent, to $23.0 million for the nine months ended September 30, 2015 compared to $30.9 million for the same period in 2014. The primary driver for the coal mining expense decrease has been the lower per ton production costs experienced in 2015 due to the increase in coal production activity at the Colowyo Mine for the first nine months of 2015 as compared to the first nine months of 2014.

Other Income

Interest income decreased $6.2 million, or 65.4 percent, to $3.2 million for the nine months ended September 30, 2015 compared to $9.4 million for the same period in 2014. The decrease in interest income was primarily due to there being no investment during 2015 in the RUS cushion of credit, which earned a 5 percent return.

Capital credits from cooperatives consist of patronage capital allocations received from other cooperatives of which we are a member, including cooperative banks, electric suppliers and service companies. Capital credits increased $2.2 million, or 59.5 percent, to $6.0 million for the nine months ended September 30, 2015 compared to $3.8 million for the same period in 2014. The increase in capital credits was primarily due to higher allocations from Trapper Mining of $1.4 million, CoBank, ACB of $0.5 million and National Rural Utilities Cooperative Finance Corporation of $0.1 million.

Financial condition as of September 30, 2015 compared to December 31, 2014

Assets

Construction work in progress decreased $30.1 million, or 14.6 percent, to $176.0 million as of September 30, 2015 compared to $206.1 million as of December 31, 2014. The decrease was primarily due to transfers to electric plant in service of $220.9 million for completed generation and transmission capital projects, partially offset by capital expenditures of $190.9 million related to various generation and transmission capital improvements and system upgrades.

Other plant consists of mine assets at Colowyo Mine and New Horizon Mine and other non-utility property. Other plant increased $19.4 million, or 9.2 percent, to $230.1 million as of September 30, 2015 compared to $210.7 million as of December 31, 2014. The increase was primarily due to the acquisition of land and water rights in northwestern Colorado related to the Colowyo Mine and mine equipment purchases.

Restricted cash and investments consist of (1) funds designated by our Board of Directors for specific uses, (2) funds restricted by contract or other legal reasons, and (3) investments in securities pledged as collateral in connection with the in-substance defeasance of debt assumed in the 2011 acquisition of Colowyo Coal. The noncurrent portion of restricted cash and investments decreased $34.5 million, or 87.5 percent, to $4.9 million as of September 30, 2015 compared to $39.4 million as of December 31, 2014. The decrease was primarily due to the BNSF settlement which resolved the uncertainties related to the outcome of this matter and the $29.4 million of cash related to the BNSF settlement was no longer designated as restricted. Additionally, $4.2 million of investment in securities pledged as collateral matured during the second quarter of 2015. The matured U.S. Treasury Notes were used for the Colowyo Bonds principal and interest due in May 2015.

Cash and cash equivalents increased $102.7 million, or 111.1 percent, to $195.2 million as of September 30, 2015 compared to $92.5 million as of December 31, 2014. The increase in cash and cash equivalents was primarily due to $231.0 million of proceeds from issuance of debt from our secured revolving credit facility (the "2011 Credit Agreement"), higher net margins and an increase in cash collected from Member accounts receivable, partially offset by payments of long-term debt of $101.8 million and purchases of plant of $217.9 million.

Coal inventory increased $29.1 million, or 71.7 percent, to $69.8 million as of September 30, 2015 compared to $40.7 million as of December 31, 2014. The increase was primarily due to an $8.8 million increase in coal inventory at the Colowyo Mine and an $18.0 million increase of Colowyo Mine coal at the Craig Generating Station as part of our coal supply planning at the station. There was also a $3.6 million increase in coal inventory at our Escalante Generating Station due to lower generation.

Equity and Liabilities

Patronage capital equity increased $74.7 million, or 8.2 percent, to $983.4 million as of September 30, 2015 compared to $908.7 million as of December 31, 2014. The increase was due to a margin attributable to us of $74.7 million for the nine months ended September 30, 2015.

Long-term debt increased $124.9 million, or 3.9 percent, to $3.291 billion as of September 30, 2015 compared to $3.166 billion as of December 31, 2014, and current maturities of long-term debt increased $3.1 million, or 3.3 percent, to $97.4 million as of September 30, 2015 compared to $94.3 million as of December 31, 2014. The total increase of $128.0 million was primarily due to debt proceeds of $231.0 million from the 2011 Credit Agreement, partially offset by debt payments of $101.8 million (primarily $34.8 million for the Springerville certificates, $27.1 million for the First Mortgage Obligations, Series 2009C, $20.0 million for the 2011 Credit Agreement, $5.0 million for the Gallup Pollution Control Revenue Bonds and $4.0 million for the Colowyo Bonds).

Accrued interest increased $16.6 million, or 50.9 percent, to $49.1 million as of September 30, 2015 compared to $32.5 million as of December 31, 2014. The increase was primarily due to the timing of interest payments related to the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, and the First Mortgage Bonds, Series 2014E-1 and E-2 that are due during the fourth quarter of 2015.

Other deferred credits decreased $21.2 million, or 35.9 percent, to $37.9 million as of September 30, 2015 compared to $59.1 million as of December 31, 2014. The decrease was primarily due to the recognition of the benefit associated with the previously unrecognized BNSF proceeds of $29.4 million pursuant to the BNSF rate settlement in June 2015.

Liquidity

We finance our operations, working capital needs and capital expenditures from operations and issuance of debt. Our liquidity as of September 30, 2015 is as follows:

	(In thousands)
Cash	$ 195,209
2011 Credit Agreement Availability	441,258
Total Liquid Funds Available	**$ 636,467**

Our 2011 Credit Agreement has aggregate commitments of $750 million which includes a swingline sublimit of $100 million and a letter of credit sublimit of $200 million, of which $100 million of the swingline sublimit and $152 million of the letter of credit sublimit remained available as of September 30, 2015. The 2011 Credit Agreement is secured under the Master Indenture and has a term extending through July 26, 2019. We had outstanding borrowings of $261 million and $50 million at September 30, 2015 and December 31, 2014, respectively, and an issued letter of credit in the principal amount of $46.8 million plus accrued interest supported by the 2011 Credit Agreement. Funds advanced under the 2011 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 September 30, 2015, we have $441 million in availability under the 2011 Credit Agreement.

Between projected cash on hand and the 2011 Credit Agreement, we believe we have sufficient liquidity to fund operations and capital financing needs.

Cash Flow

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

September 30, 2015 compared to September 30, 2014

Operating activities. Net cash provided by operating activities was $195.2 million for the nine months ended September 30, 2015 compared to $208.7 million for the same period in 2014, a decrease of $13.5 million. Operating activities in 2015 were impacted by a $29.1 million increase in coal inventory (primarily at Craig Generating Station), a $10.8 million decrease in accounts payable and accrued expenses related to the timing of the payment of trade payables and accrued expenses, and a $4.1 million increase in materials and supplies due to the timing of various generation projects. Operating activities were also impacted by a $21.0 million increase in cash collected from Member accounts receivable resulting from higher seasonal irrigation and oil and gas loads, $29.4 million of previously restricted cash related to the BNSF settlement that was available for operations in 2015, and higher net margins.

Investing activities. Net cash used in investing activities was $216.0 million for the nine months ended September 30, 2015 compared to $156.7 million for the same period in 2014, an increase of $59.3 million. The increase in investing activities was primarily due to higher capital expenditures for generation and transmission improvements and system upgrades to serve the growing needs of our Members and to comply with environmental requirements.

Financing activities. Net cash provided by financing activities was $123.6 million for the nine months ended September 30, 2015 compared to net cash used in financing activities of $114.6 million for the same period in 2014, an increase of $238.2 million. The increase in financing activities was primarily due to higher proceeds from issuance of debt ($231.0 million from our 2011 Credit Agreement for the nine months ended September 30, 2015 compared to $80.0 million from our 2011 Credit Agreement for the nine months ended September 30, 2014) partially offset by lower debt payments ($101.8 million for the nine months ended September 30, 2015 compared to $273.3 million for the nine months ended September 30, 2014).

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. In the years 2015 through 2019, we estimate that we may invest approximately $1.9 billion in new facilities and upgrades to our existing facilities.

Our actual capital expenditures for existing and new generating facilities and existing and new transmission facilities going forward depend on a variety of factors, including Member load growth, availability of necessary permits, 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. Other capital projects include several transmission projects, such as expansion in the Interstate 25 corridor north of Denver, construction of the Southwest Colorado Transmission Reliability Project, and additional projects to improve reliability and load-serving capability throughout our service area. As of September 30, 2015, we have incurred capital expenditures of approximately $92.9 million in connection with the expansion project of an existing coal-fired generating station called

Holcomb Generating Station, which we refer to as Holcomb, and approximately $70.6 million in connection with a possible generating station in southeastern Colorado, which we refer to as the Colorado Power Project. Additional capital expenditures for Holcomb and the Colorado Power Project are not included in our current capital expenditure projections.

Contractual Commitments

Indebtedness. As of September 30, 2015, we had approximately $2.8 billion of debt outstanding secured on a parity basis under the 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 one term loan which is unsecured), 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 pollution control revenue bonds, and amounts outstanding under the 2011 Credit Agreement. Substantially all of our assets are pledged as collateral under the Master Indenture. 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 72 MWs which began on October 1, 2009. 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.

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.

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

Environmental Regulations

We are subject to various federal, state and local laws, rules and regulations with regard to air quality, including greenhouse gases, water quality, and other environmental matters. These environmental laws, rules and regulations are complex, change frequently and have become more stringent and numerous over time. Below are various proposed and recently enacted regulations that may impact us.

Clean Power Plan. In 2014, the Environmental Protection Agency, or EPA, proposed emission limits and emission guidelines of carbon dioxide for existing generating facilities in a comprehensive proposed rule referred to as the ‘‘Clean Power Plan.’’ On August 3, 2015, the EPA issued a pre-publication version of a final rule regarding emissions of carbon dioxide from certain fossil fuel-fired electric generating units. On October 23, 2015, the final rule was published in the Federal Register. The Clean Power Plan establishes guidelines for states to develop plans to limit emissions of carbon dioxide from existing units. The goal of the rule is a reduction in carbon dioxide emissions from 2005 levels of 32 percent nationwide by 2030 and specifies interim emission rates phasing in between 2022 and 2029. At this time it is not possible to understand how we will be impacted (financially or operationally) in each state, as that information will be developed in state specific plans that will be submitted to the EPA by September 2016. The EPA will take a year to review and approve state plans. States may request an extension up to September 2018. Once approved, states must implement their plan to ensure power plants achieve the interim carbon dioxide emissions performance goals. The final state goals in year 2030 and beyond under the Clean Power Plan for the five states where we would be impacted are as follows: Arizona—1,031 lb/MWh; Colorado—1,174 lb/MWh; Nebraska—1,296 lb/MWh; New Mexico—1,146 lb/MWh; and Wyoming—1,299 lb/MWh. Each of these goals is substantially below the carbon dioxide emission rate of a well-designed coal-fired unit and assumes increased reliance on a combination of natural gas-fired and renewable energy sources, with coal-fired generation being dispatched less often or curtailed entirely. The EPA also proposed a federal plan that would be implemented should states fail to submit acceptable plans. Comments on the proposed federal plan are due January 21, 2016. The Clean Power Plan is the most complex and wide-ranging regulation under the Clean Air Act. We, along with various states and other utilities, have filed petitions for review of the Clean

Power Plan with the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit Court of Appeals. The Clean Power Plan does not directly impose regulatory requirements on our operations. The impacts of the final rule and any subsequent challenges cannot be determined at this time; however, it could have a material impact on our operations, including increased operating costs, additional investment in new generation (natural gas and renewables), investment in energy efficiency programs and decreased operation, or closure of coal-fired plants. On October 23, 2015, the EPA also issued a final New Source Performance Standard, or NSPS, for new and modified units that establishes carbon dioxide emission standards for plants built in the future. This NSPS does not create emission standards for Holcomb, but states that if the plant moves forward, EPA will create a separate rule for Holcomb due to the fact that it is so far along in the process.

Mercury and Air Toxics Standards. In 2012, the EPA finalized the Mercury and Air Toxics Standards, or MATS, rulemaking with emissions standards across four categories of emissions, with a compliance deadline in April 2015. We were among the parties that legally challenged the MATS rule, but the rule was upheld by the D.C. Circuit Court of Appeals in April 2014. The Supreme Court agreed to review a narrow provision that focuses on whether the EPA reasonably considered costs in developing the MATS, and oral arguments in the case were heard in March 2015. In June 2015, the Supreme Court reversed the D.C. Circuit Court's decision and remanded the case to the D.C. Circuit Court for further proceedings, finding that the EPA erred in refusing to consider costs when deciding whether it was appropriate and necessary to regulate emissions of hazardous air pollutants from steam electric generating units. Pending action by the D.C. Circuit Court, the rule remains in effect. The Colorado Department of Public Health and Environment approved our request to extend the MATS hydrochloric acid mist compliance date to April 16, 2016 for the Nucla Generating Station. In July 2015, we filed an emergency motion with the D.C. Circuit Court requesting the court to suspend the compliance obligation of the MATS rule for the Nucla Generating Station regarding hydrochloric acid in light of the Supreme Court decision. The EPA replied to the emergency motion and provided relief from the interim compliance reporting deadline. The next compliance deadline for MATS at Nucla Generating Station is April 2016. We intend to apply for an administrative order to obtain an additional year extension as allowed under the EPA regulations. We cannot predict the outcome of this proceeding.

State Implementation Plans. On June 12, 2015, the EPA published a final action in the Federal Register that takes action under the Clean Air Act, or CAA, enacting State Implementation Plan, or SIP, calls on states to change provisions to the current affirmative defense used by utilities in the event they have excess emissions during a startup, shutdown or malfunction events. States retain broad discretion concerning how to revise their SIP, so long as that revision is consistent with the requirements of the CAA. The EPA issued the SIP call for 36 states, including AZ, CO, NM, and WY. The EPA established a deadline of November 22, 2016, by which those states must make SIP submissions to rectify the specifically identified deficiencies in their respective SIPs. We are working with state environmental agencies to address changes to SIPs in each noted state. We cannot predict the outcome of these proceedings at this time.

Waters of the United States, or WOTUS. On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a rule that revises the regulatory definition of waters of the U.S. for all Clean Water Act programs, significantly expanding the scope of federal jurisdiction. On August 29, 2015, the United States District Court for the District of North Dakota issued a preliminary injunction against the WOTUS rule delaying the effective date of the rule for thirteen states, including all states that we operate in. The court noted that it appears likely that the EPA has violated its congressional authority in its promulgation of the rule and the EPA may have failed to comply with the Administrative Procedures Act. On October 9, 2015, the United States Court of Appeals for the Sixth Circuit issued a nationwide stay on the WOTUS rule pending further order of the court.

Effluent Guidelines for Electric Generating Units. On September 30, 2015, the EPA signed the effluent limitation guidelines for steam electric units. We expect minimal impact on our operations due to limited water discharge from our power plants.

Ozone National Ambient Air Quality Standards, or NAAQS. On October 1, 2015, the EPA issued final NAAQS rule revisions for ozone and reduced the limit from 75 parts per billion to 70 parts per billion. Based on current data available in the states that we operate in, there are several of our operations that may be located in non-attainment areas, including J.M. Shafer and Knutson Generating Stations. States have several years to implement the standards and determine ozone non-attainment areas. The impacts of the final rule and any subsequent challenges cannot be determined at this time.

Rating Triggers

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s, “A (negative outlook)” by S&P, and “A (negative outlook)” by Fitch.

The 2011 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 and financial risk management contracts. Some of the contracts are directly tied to our credit rating being maintained at “BBB-” or better from S&P or “Baa3” from Moody’s. We expect to enter into additional natural gas supply contracts and/or risk management contracts which will 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 72 MWs which began on October 1, 2009. 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 Registration Statement on Form S-4 (Registration No. 333-203560) that was declared effective by the SEC on July 29, 2015.

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 11 - 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: November 12, 2015

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

Date: November 12, 2015

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