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, 2022
OR

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

For the transition period from to

Commission File No. 333-212006

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

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. **Yes** ☐ **No** ☒ (Note: The registrant is not subject to the filing requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), but voluntarily files reports with the Securities and Exchange Commission).

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). **Yes** ☒ **No** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. **Large accelerated filer** ☐ **Accelerated filer** ☐

Non-accelerated Filer ☒ **Smaller reporting company** ☐ **Emerging growth company** ☐

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

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

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

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

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

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2022

GLOSSARY

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

Abbreviations or Acronyms	Definition
2022 Revolving Credit Agreement	Amended and Restated Credit Agreement, dated as of April 25, 2022, between us and CFC, as administrative agent
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Basin	Basin Electric Power Cooperative
Board	Board of Directors
CDPHE	Colorado Department of Public Health and Environment
CFC	National Rural Utilities Cooperative Finance Corporation
CoBank	CoBank, ACB
Colowyo Coal	Colowyo Coal Company L.P., a subsidiary of ours
COPUC	Colorado Public Utilities Commission
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
DSR	Debt Service Ratio (as defined in our Master Indenture)
ECR	Equity to Capitalization Ratio (as defined in our Master Indenture)
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
Jurisdictional PDO	our Petition for Declaratory Order on Jurisdiction under Part II of Federal Power Act, filed with FERC on December 23, 2019, EL20-16-000
kWh	kilowatt hour
LPEA	La Plata Electric Association, Inc.
Master Indenture	Master First Mortgage Indenture, Deed of Trust and Security Agreement, dated effective as of December 15, 1999, between us and U.S. Bank Trust Company, National Association, as successor trustee
MBPP	Missouri Basin Power Project
Members	our Utility Members and Non-Utility Members
Moody’s	Moody’s Investors Services, Inc.
MW	megawatt
MWh	megawatt hour
Non-Utility Members	our non-utility members
OATT	Open Access Transmission Tariff
S&P	S & P Global Ratings
Salt River Project	Salt River Project Agricultural Improvement and Power District
SEC	Securities and Exchange Commission
Springerville Partnership	Springerville Unit 3 Partnership LP, a subsidiary of ours
Springerville Unit 3	Springerville Generating Station Unit 3
Term SOFR	the implied rate on the future movement in the Secured Overnight Financing Rate (or "SOFR") over a future reference period
Tri-State, We, Our, Us, the Association	Tri-State Generation and Transmission Association, Inc.
United Power	United Power, Inc.

Utility Members	our electric distribution member systems, consisting of both Class A members and Class B members
WACM	Western Area Colorado Missouri

FORWARD-LOOKING STATEMENTS

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

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

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

	September 30, 2022	December 31, 2021
ASSETS	(Unaudited)	
Property, plant and equipment		
Electric plant		
In service	$ 5,678,492	$ 5,606,732
Construction work in progress	81,396	107,636
Total electric plant	**5,759,888**	**5,714,368**
Less allowances for depreciation and amortization	(2,412,145)	(2,367,197)
Net electric plant	**3,347,743**	**3,347,171**
Other plant	981,018	1,093,922
Less allowances for depreciation, amortization and depletion	(687,844)	(823,087)
Net other plant	**293,174**	**270,835**
Total property, plant and equipment	**3,640,917**	**3,618,006**
Other assets and investments		
Investments in other associations	161,949	163,097
Investments in and advances to coal mines	2,044	2,273
Restricted cash and investments	3,585	4,101
Other noncurrent assets	16,299	15,873
Total other assets and investments	**183,877**	**185,344**
Current assets		
Cash and cash equivalents	107,228	100,555
Restricted cash and investments	17,404	480
Deposits and advances	33,432	34,042
Accounts receivable—Utility Members	108,107	95,630
Other accounts receivable	27,833	21,571
Land held for sale	41	—
Coal inventory	40,202	59,701
Materials and supplies	92,719	87,234
Total current assets	**426,966**	**399,213**
Deferred charges		
Regulatory assets	664,151	665,693
Prepayment—NRECA Retirement Security Plan	12,088	16,117
Other	42,255	35,139
Total deferred charges	**718,494**	**716,949**
Total assets	**$ 4,970,254**	**$ 4,919,512**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 974,496	$ 994,865
Accumulated other comprehensive loss	(2,575)	(1,460)
Noncontrolling interest	124,046	119,100
Total equity	**1,095,967**	**1,112,505**
Long-term debt	2,884,495	3,101,870
Total capitalization	**3,980,462**	**4,214,375**
Current liabilities		
Utility Member advances	20,068	17,217
Accounts payable	116,578	105,965
Short-term borrowings	264,485	49,997
Accrued expenses	29,913	32,882
Current asset retirement obligations	6,635	7,003
Accrued interest	42,826	25,716
Accrued property taxes	29,565	33,877
Current maturities of long-term debt	87,499	93,039
Total current liabilities	**597,569**	**365,696**
Deferred credits and other liabilities		
Regulatory liabilities	87,366	146,021
Deferred income tax liability	19,641	18,987
Asset retirement and environmental reclamation obligations	197,414	83,278
Other	74,884	78,319
Total deferred credits and other liabilities	**379,305**	**326,605**
Accumulated postretirement benefit and postemployment obligations	12,918	12,836
Total equity and liabilities	**$ 4,970,254**	**$ 4,919,512**

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,	
	2022	**2021**	**2022**	**2021**
Operating revenues				
Utility Member electric sales	$ 362,442	$ 350,344	$ 931,257	$ 897,587
Non-member electric sales	55,669	35,876	110,029	75,808
Rate stabilization	32,950	8,575	58,295	49,365
Provision for rate refunds	(2,039)	—	759	(6,403)
Other	16,971	21,068	42,817	51,780
	465,993	**415,863**	**1,143,157**	**1,068,137**
Operating expenses				
Purchased power	128,202	112,540	321,240	286,109
Fuel	94,770	76,332	225,491	182,749
Production	40,045	41,543	128,095	135,285
Transmission	47,054	50,152	136,289	136,771
General and administrative	18,658	15,916	57,824	42,400
Depreciation, amortization and depletion	46,604	44,990	133,347	144,228
Coal mining	1,814	1,492	7,189	3,999
Other	2,288	1,562	50,626	5,395
	379,435	**344,527**	**1,060,101**	**936,936**
Operating margins	**86,558**	**71,336**	**83,056**	**131,201**
Other income				
Interest	1,097	897	2,883	2,681
Capital credits from cooperatives	743	59	5,338	4,334
Other income (expense)	1,751	1,358	2,621	3,247
	3,591	**2,314**	**10,842**	**10,262**
Interest expense				
Interest	38,419	35,739	109,409	107,946
Interest charged during construction	(341)	(861)	(1,133)	(2,839)
	38,078	**34,878**	**108,276**	**105,107**
Income tax expense (benefit)	(312)	267	(275)	486
Net margins including noncontrolling interest	**52,383**	**38,505**	**(14,103)**	**35,870**
Net margin attributable to noncontrolling interest	(2,130)	(1,765)	(6,266)	(5,176)
Net margins attributable to the Association	**$ 50,253**	**$ 36,740**	**$ (20,369)**	**$ 30,694**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	**2021**	**2022**	**2021**
Net margins including noncontrolling interest	$ 52,383	$ 38,505	$ (14,103)	$ 35,870
Other comprehensive loss:				
Unrealized loss on securities available for sale	(127)	(15)	(360)	(56)
Amortization of prior service credit on postretirement benefit obligation included in net margin	(535)	(20)	(1,604)	(60)
Amortization of actuarial loss on executive benefit restoration obligation included in net margin	—	—	—	312
Amortization of prior service cost on executive benefit restoration obligation included in net margin	283	240	849	699
Unrecognized prior service cost	—	—	—	(1,121)
Other comprehensive income (loss)	**(379)**	**205**	**(1,115)**	**(226)**
Comprehensive income (loss) including noncontrolling interest	**52,004**	**38,710**	**(15,218)**	**35,644**
Net comprehensive income attributable to noncontrolling interest	(2,130)	(1,765)	(6,266)	(5,176)
Comprehensive income (loss) attributable to the Association	**$ 49,874**	**$ 36,945**	**$ (21,484)**	**$ 30,468**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	**2021**	**2022**	**2021**
Patronage capital equity at beginning of period	$ 924,243	$ 972,473	$ 994,865	$ 978,519
Net margins attributable to the Association	50,253	36,740	(20,369)	30,694
Patronage capital equity at end of period	**974,496**	**1,009,213**	**974,496**	**1,009,213**
Accumulated other comprehensive loss at beginning of period	(2,196)	(6,145)	(1,460)	(5,714)
Unrealized loss on securities available for sale	(127)	(15)	(360)	(56)
Reclassification adjustment of prior service credit on postretirement benefit obligation included in net margin	(535)	(20)	(1,604)	(60)
Reclassification adjustment for actuarial loss on executive benefit restoration obligation included in net margin	—	—	—	312
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	283	240	849	699
Unrecognized prior service cost	—	—	—	(1,121)
Accumulated other comprehensive loss at end of period	**(2,575)**	**(5,940)**	**(2,575)**	**(5,940)**
Noncontrolling interest at beginning of period	122,894	115,569	119,100	114,851
Net comprehensive income attributable to noncontrolling interest	2,130	1,765	6,266	5,176
Equity distribution to noncontrolling interest	(978)	—	(1,320)	(2,693)
Noncontrolling interest at end of period	**124,046**	**117,334**	**124,046**	**117,334**
Total equity at end of period	**$ 1,095,967**	**$ 1,120,607**	**$ 1,095,967**	**$ 1,120,607**

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,	
	2022	**2021**
Operating activities		
Net margins including noncontrolling interest	$ (14,103)	$ 35,870
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	133,347	144,228
Amortization of NRECA Retirement Security Plan prepayment	4,029	4,029
Amortization of debt issuance costs	2,540	1,867
Impairment loss	30,153	—
Deferred impairment loss	(30,153)	—
Rate stabilization revenue	(58,295)	(49,365)
Deposits associated with generator interconnection requests	6,626	17,130
Capital credit allocations from cooperatives and income from coal mines under (over) refund distributions	1,283	(1,180)
Changes in operating assets and liabilities:		
Accounts receivable	(23,666)	(12,991)
Coal inventory	19,499	(2,064)
Materials and supplies	(5,486)	(1,977)
Accounts payable and accrued expenses	14,837	27,258
Accrued interest	17,110	17,397
Accrued property taxes	(4,312)	(5,856)
New Horizon Mine environmental obligation	44,869	—
Other	(12,517)	(3,653)
Net cash provided by operating activities	**125,761**	**170,693**
Investing activities		
Purchases of plant	(82,846)	(83,405)
Changes in deferred charges	(5,849)	(15,734)
Proceeds from other investments	94	72
Net cash used in investing activities	**(88,601)**	**(99,067)**
Financing activities		
Changes in Member advances	2,717	2,499
Early payments for open market purchases and tender offer	(136,692)	(4,205)
Scheduled payments of long-term debt	(86,886)	(82,933)
Debt issuance costs	(1,377)	—
Change in short-term borrowings, net	214,488	—
Retirement of patronage capital	(4,564)	(13,705)
Equity distribution to noncontrolling interest	(1,320)	(2,693)
Other	(445)	(409)
Net cash used in financing activities	**(14,079)**	**(101,446)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**23,081**	**(29,820)**
Cash, cash equivalents and restricted cash and investments – beginning	**105,136**	**132,074**
Cash, cash equivalents and restricted cash and investments – ending	**$ 128,217**	**$ 102,254**
Supplemental cash flow information:		
Cash paid for interest	$ 88,993	$ 89,119
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (2,783)	$ 2,730

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, 2022 and 2021

NOTE 1 – PRESENTATION OF FINANCIAL INFORMATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) for interim financial information and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. These unaudited consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2021 filed with the SEC. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. Our consolidated financial position as of September 30, 2022, results of operations for the three and nine months ended September 30, 2022 and 2021, and cash flows for the nine months ended September 30, 2022 and 2021 are not necessarily indicative of the results that may be expected for an entire year or any other period.

Basis of Consolidation

We are a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis serving large portions of Colorado, Nebraska, New Mexico and Wyoming. We were incorporated under the laws of the State of Colorado in 1952. We have three classes of membership: Class A - utility full requirements members, Class B - utility partial requirements members, and non-utility members. We have forty-two electric distribution member systems who are Class A members to which we provide electric power pursuant to long-term wholesale electric service contracts. We currently have no Class B members. We have three non-utility members (“Non-Utility Members”). Our Class A members and any Class B members are collectively referred to as our “Utility Members.” Our Class A members, any Class B members, and Non-Utility Members are collectively referred to as our “Members.” The addition of Non-Utility Members in 2019 and specifically the addition of MIECO, Inc. on September 3, 2019 removed the exemption from the Federal Energy Regulatory Commission’s (“FERC”) regulation for us, thus subjecting us to full rate and transmission jurisdiction by FERC effective September 3, 2019. Our stated rate to our Class A members was filed at FERC on December 23, 2019 and was accepted by FERC on March 20, 2020. On August 2, 2021, FERC approved our settlement agreement related to our stated rate to our Class A members. See Note 17 – Legal.

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

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

Jointly Owned Facilities

We own undivided interests in two jointly owned generating facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Yampa Project (operated by us) and the Missouri Basin Power Project (“MBPP”) (operated by Basin Electric Power Cooperative (“Basin”)). Each participant in these agreements receives a portion of the total output of the generating facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and other operating expenses is included in our consolidated financial statements.

Our share in each jointly owned facility is as follows as of September 30, 2022 (dollars in thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Generating Station Units 1 and 2	24.00 %	$ 391,689	$ 259,518	$ 80
MBPP - Laramie River Station	28.50 %	526,250	340,519	4,956
Total		$ 917,939	$ 600,037	$ 5,036

NOTE 2 – ACCOUNTING FOR RATE REGULATION

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

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

	September 30, 2022	December 31, 2021
Regulatory assets		
Deferred income tax expense (1)	$ 19,671	$ 18,742
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	77,415	79,133
Goodwill – J.M. Shafer (3)	41,310	43,447
Goodwill – Colowyo Coal (4)	34,353	35,128
Deferred debt prepayment transaction costs (5)	117,203	123,674
Deferred Holcomb expansion impairment loss (6)	80,639	84,145
Unrecovered plant (7)	293,560	281,424
Total regulatory assets	664,151	665,693
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	2,458	2,818
Membership withdrawal (9)	84,908	143,203
Total regulatory liabilities	87,366	146,021
Net regulatory asset	$ 576,785	$ 519,672

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

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

(3) Represents goodwill related to our acquisition of an entity that owned J.M. Shafer Generating Station in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Utility Members through rates.

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

(5) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of $8.6 million annually over the 21.4-year period ending in 2036 and recovered from our Utility Members through rates.
(6) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights for the expansion of the Holcomb Generating Station. The regulatory asset for the deferred impairment loss is being amortized to depreciation, amortization and depletion expense in the amount of $4.7 million annually over the 20-year period ending in 2039 and recovered from our Utility Members through rates.
(7) Represents deferral of the impairment losses related to the early retirement of the Nucla, Escalante and Rifle Generating Stations. The deferred impairment loss for Nucla and Escalante Generating Stations is being amortized to depreciation, amortization and depletion expense in the remaining amount of $4.5 million through December 2022 and $12.3 million annually over the 25-year period ending in December 2045, respectively, and recovered from our Utility Members through rates. In March 2022, our Board took action for the early retirement of the Rifle Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement, we recognized an impairment loss of $3.7 million during the first quarter of 2022. The Rifle Generating Station was retired from service on September 30, 2022. The deferred impairment loss is being amortized to depreciation, amortization and depletion expense in the amount of $0.6 million annually through December 2028, which was the depreciable life of the Rifle Generating Station, and recovered from our Utility Members in rates.
(8) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A and refunded to Utility Members through reduced rates when recognized in future periods.
(9) Represents the deferral of the recognition of other operating revenues related to the withdrawal of former Utility Members from membership in us. The deferred membership withdrawal income will be refunded to Utility Members through reduced rates when recognized in operating revenues in future periods. For the nine months ended September 30, 2022, $58.3 million was recognized in operating revenues as part of our rate stabilization measures.

NOTE 3 – INVESTMENTS IN OTHER ASSOCIATIONS

Investments in other associations include investments in the patronage capital of other cooperatives and other required investments in the organizations. Our investment in a cooperative increases when a cooperative allocates patronage capital credits to us and it decreases when we receive a cash retirement of the allocated capital credits from the cooperative. A cooperative allocates its patronage capital credits to us based upon our patronage (amount of business done) with the cooperative.

Investments in other associations are as follows (dollars in thousands):

	September 30, 2022	December 31, 2021
Basin Electric Power Cooperative	$ 114,412	$ 116,826
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,172	12,076
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,054	15,149
CoBank, ACB	14,328	12,985
Other	5,983	6,061
Investments in other associations	$ 161,949	$ 163,097

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during the nine months ended September 30, 2022 or during 2021.

NOTE 4 – CASH, CASH EQUIVALENTS AND RESTRICTED CASH AND INVESTMENTS

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

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

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

	September 30, 2022	December 31, 2021
Cash and cash equivalents	$ 107,228	$ 100,555
Restricted cash and investments - current	17,404	480
Restricted cash and investments - noncurrent	3,585	4,101
Cash, cash equivalents and restricted cash and investments	$ 128,217	$ 105,136

NOTE 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

Accounts Receivable

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

Contract liabilities (unearned revenue)

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. During the nine months ended September 30, 2022, we recognized $0.6 million of this unearned revenue in other operating revenues on our consolidated statements of operations.

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

	September 30, 2022	December 31, 2021
Accounts receivable - Utility Members	$ 108,107	$ 95,630
Other accounts receivable - trade:		
Non-member electric sales	17,613	5,684
Other	4,710	13,505
Total other accounts receivable - trade	22,323	19,189
Other accounts receivable - nontrade	5,510	2,382
Total other accounts receivable	$ 27,833	$ 21,571
Contract liabilities (unearned revenue)	$ 5,261	$ 5,372

NOTE 6 – OTHER DEFERRED CHARGES

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

	September 30, 2022	December 31, 2021
Preliminary surveys and investigations	$ 12,846	$ 12,366
Advances to operating agents of jointly owned facilities	9,420	4,422
Operating lease right-of-use assets	6,679	7,529
Other	13,310	10,822
Total other deferred charges	$ 42,255	$ 35,139

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

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

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

NOTE 7 – LONG-TERM DEBT

We have $2.9 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture") except for one unsecured note in the amount of $6.1 million as of September 30, 2022. Due to a public tender offer which was completed in July 2022, $100.0 million of our First Mortgage Bonds, Series 2014E-1 were repurchased with cash and short-term borrowings. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a debt service ratio requirement on an annual basis and an equity to capitalization ratio requirement of at least 18 percent at the end of each fiscal year. Other than the Springerville certificates that has a debt service ratio requirement of at least 1.02 on an annual basis, all other long-term debt contains a debt service ratio requirement of at least 1.10 on an annual basis.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC"), as lead arranger and administrative agent, in the amount of $520 million ("2022 Revolving Credit Agreement") that expires on April 25, 2027 and includes a swingline sublimit of $125 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million. As of September 30, 2022, we had $255.5 million in availability under the 2022 Revolving Credit Agreement.

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

	September 30, 2022	December 31, 2021
Total debt	$ 2,990,849	$ 3,214,427
Less debt issuance costs	(21,948)	(23,110)
Less debt discounts	(9,039)	(9,398)
Plus debt premiums	12,132	12,990
Total debt adjusted for debt issuance costs, discounts and premiums	2,971,994	3,194,909
Less current maturities	(87,499)	(93,039)
Long-term debt	$ 2,884,495	$ 3,101,870

NOTE 8 – SHORT-TERM BORROWINGS

We have a commercial paper program under which we issue unsecured commercial paper in aggregate amounts not exceeding the commercial paper back-up sublimit under our 2022 Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our 2022 Revolving Credit Agreement. The commercial paper issuances are used to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances vary but may not exceed 397 days from the date of issue. The commercial paper notes are classified as current and are included in current liabilities as short-term borrowings on our consolidated statements of financial position.

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

	September 30, 2022	December 31, 2021
Commercial paper outstanding, net of discounts	$ 264,485	$ 49,997
Weighted average interest rate	3.15 %	0.19 %

At September 30, 2022, $235.5 million of the commercial paper back-up sublimit remained available under the 2022 Revolving Credit Agreement. See Note 7 – Long-Term Debt.

NOTE 9 – ASSET RETIREMENT AND ENVIRONMENTAL RECLAMATION OBLIGATIONS

We account for current obligations associated with the future retirement of tangible long-lived assets and environmental reclamation in accordance with the accounting guidance relating to asset retirement and environmental obligations. This guidance requires that legal obligations associated with the retirement of long-lived assets be recognized at fair value at the time the liability is incurred and capitalized as part of the related long-lived asset. Over time, the liability is adjusted to its present value by recognizing accretion expense and the capitalized cost of the long-lived asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. In the absence of quoted market prices, we determine fair value by using present value techniques in which estimates of future cash flows associated with retirement activities are discounted using a credit adjusted risk-free rate and market risk premium. Upon settlement of an asset retirement obligation, we will apply payment against the estimated liability and incur a gain or loss if the actual retirement costs differ from the estimated recorded liability.

Environmental reclamation costs are accrued based on management’s best estimate at the end of each period of the costs expected to be incurred. Such cost estimates may include ongoing care, maintenance and monitoring costs. Changes in reclamation estimates are reflected in earnings in the period an estimate is revised.

Coal mines: We have asset retirement obligations for the final reclamation costs and environmental obligations for post-reclamation monitoring related to the Colowyo Mine and the New Horizon Mine. The New Horizon Mine is currently in post-reclamation monitoring. One pit at the Colowyo Mine began final reclamation in 2020 with the other remaining pits still being actively mined.

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

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

	Nine Months Ended September 30, 2022
Obligations at beginning of period	$ 90,281
Liabilities settled	(4,918)
Accretion expense	2,553
Change in estimate	116,133
Total obligations at end of period	$ 204,049
Less current obligations at end of period	(6,635)
Long-term obligations at end of period	$ 197,414

In the third quarter of 2022, we increased the asset retirement obligations related to two pits at the Colowyo Mine by $39.2 million due to revised cost estimates, with an offsetting decrease in the asset retirement obligation related to the third pit of $6.3 million due to updated final reclamation cost estimates. In the second quarter of 2022, we increased the environmental reclamation obligation at the New Horizon Mine by $44.9 million due to revised cost estimates. The New Horizon Mine environmental remediation liability that has been recorded is $67.3 million as of September 30, 2022. Of this amount, $36.8 million is recorded on a discounted basis, using a discount rate of 3.25 percent, with total estimated undiscounted future cash outflows of $57.9 million. Environmental obligation expense is included in other operating expenses on our consolidated statement of operations. Although the entire environmental obligation has been expensed, we may seek future rate recovery in upcoming rate filings with FERC. We continue to evaluate the New Horizon Mine and Colowyo Mine post reclamation obligations and will make adjustments to these obligations as needed. Also during 2022, we recorded an additional asset retirement obligation of $38.4 million related to a change in cost estimates for our pond, ash landfill and post-closure reclamation obligations at various generating stations.

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

NOTE 10 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES

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

	September 30, 2022	December 31, 2021
Transmission easements	$ 18,857	$ 19,339
Operating lease liabilities - noncurrent	1,327	1,622
Contract liabilities (unearned revenue) - noncurrent	3,659	3,523
Customer deposits	12,075	9,287
Financial liabilities - reclamation	11,447	13,122
OATT deposits	20,586	24,327
Other	6,933	7,099
Total other deferred credits and other liabilities	$ 74,884	$ 78,319

In 2015, we renewed transmission right-of-way easements on tribal nation lands where certain of our electric transmission lines are located. $27.8 million will be paid by us for these easements from 2022 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were $18.9 million and $19.3 million as of September 30, 2022 and December 31, 2021, respectively, which are recorded as other deferred credits and other liabilities.

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

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

Financial liabilities - reclamation represents the financial obligation for our share of reclamation at San Juan Mine (related to our former ownership in the San Juan Generating Station) and our share of reclamation at Laramie River Station (related to our ownership share in MBPP).

OATT deposits primarily represent deposits that are received by us related to generator interconnection requests that may be returned if the project does proceed to completion.

NOTE 11 – EMPLOYEE BENEFIT PLANS

Postretirement Benefits Other Than Pensions

We sponsor three medical plans for all non-bargaining unit employees under the age of 65. Two of the plans provide postretirement medical benefits to full-time non-bargaining unit employees and retirees who receive benefits under those plans, who have attained age 55, and who elect to participate. All three of these non-bargaining unit medical plans offer post employment medical benefits to employees on long-term disability. The plans were unfunded at September 30, 2022, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles. As of June 30, 2021, the plans ceased to provide postretirement medical benefits for employees who retire after June 30, 2021.

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

	Nine Months Ended September 30, 2022
Postretirement medical benefit obligation at beginning of period	$ 2,809
Service cost	—
Interest cost	27
Benefit payments (net of contributions by participants)	(485)
Postretirement medical benefit obligation at end of period	$ 2,351
Postemployment medical benefit obligation at end of period	392
Total postretirement and postemployment medical obligations at end of period	$ 2,743

The service cost component of our net periodic benefit cost, if any, is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations.

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

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

	Nine Months Ended September 30, 2022
Accumulated other comprehensive income at beginning of period	$ 3,580
Amortization of prior service credit into other income	(1,604)
Accumulated other comprehensive income at end of period	$ 1,976

Defined Benefit Plans

We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan, both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees with a hire date prior to May 1, 2021 participate in one of the following pension restoration plans: the NRECA Pension Restoration Plan or the NRECA Executive Benefit Restoration Plan. Eligibility is determined annually and is based on January 1 base salary that exceeds the limits of the defined benefit plan. Employees hired May 1, 2021 or later are not eligible for either plan.

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

	Nine Months Ended September 30, 2022
Executive benefit restoration obligation at beginning of period	$ 9,852
Service cost	277
Interest cost	157
Benefit payments	(111)
Executive benefit restoration at end of period	$ 10,175
Fair value of plan assets at beginning of period	$ 8,640
Employer contributions	909
Actual return on plan assets	$ (665)
Fair value of plan assets at end of period	$ 8,884
Net liability recognized at end of period	$ 1,291

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

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

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

	Nine Months Ended September 30, 2022
Accumulated other comprehensive loss at beginning of period	$ (4,932)
Amortization of prior service cost into other income	849
Accumulated other comprehensive loss at end of period	$ (4,083)

NOTE 12 – REVENUE

Revenue from Contracts with Customers

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

Member electric sales

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Non-member electric sales:				
Long-term contracts	$ 13,682	$ 11,380	$ 38,932	$ 30,179
Short-term contracts	41,987	24,496	71,097	45,629
Rate stabilization	32,950	8,575	58,295	49,365
Provision for rate refunds	(2,039)	—	759	(6,403)
Other	16,971	21,068	42,817	51,780
Total non-member electric sales and other operating revenue	$ 103,551	$ 65,519	$ 211,900	$ 170,550

Non-member electric sales

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

Rate Stabilization Revenue

We recognized $33.0 million and $58.3 million of deferred membership withdrawal income for the three and nine months ended September 30, 2022, respectively, as directed by our Board. See Note 2 - Accounting for Rate Regulation.

Provision for Rate Refunds

Based upon a FERC order requiring us to refund certain revenue from power sales in the Western Area Colorado Missouri ("WACM") balancing authority area, in the third quarter of 2022, we reserved $2.0 million as a preliminary estimate of the amount to be refunded. See Note 17 - Legal - FERC Market Based Rate Authority. Such an amount was offset by the recognition of a favorable adjustment during the second quarter of 2022 of approximately $2.9 million for the amount in excess of an accrual that was previously recorded related to certain energy sales to third parties in excess of the soft-cap for short-term, spot market sales of $1,000 per megawatt hour established by the Western Electricity Coordinating Council. See Note 17 - Legal- Energy Sales -Soft-Cap.

Other operating revenue

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

NOTE 13 – INCOME TAXES

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes, which requires that deferred tax assets and liabilities be determined based on the expected future income tax consequences of events that have been recognized in the consolidated financial statements. Effective January 1, 2020, we adopted the normalization method of recognizing deferred income taxes pursuant to FERC regulation. Under the normalization method, changes in deferred tax assets or liabilities result in deferred income tax expense (benefit) and any recorded income tax expense (benefit) therefore includes both the current income tax expense (benefit) and the deferred income tax expense (benefit).

Our subsidiaries are not subject to FERC regulation and continue to use a flow-through method for recognizing deferred income taxes whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability, as approved by our Board. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues.

Under ASC 740-270, we calculate an estimate of the provision for income taxes during interim reporting periods by applying an estimate of the annual effective tax rate for the full fiscal year to income or loss (pretax income or loss excluding unusual or infrequently occurring discrete items) for the reporting period. Our consolidated statements of operations included an income tax benefit of $0.3 million for the nine months ended September 30, 2022 and income tax expense of $0.5 million for the comparable period in 2021.

On August 16, 2022, the Inflation Reduction Act of 2022 (the "IRA") was enacted into law. The IRA imposes a 15 percent minimum tax based on consolidated GAAP profits of $1 billion or more. As a cooperative operating primarily for the benefit of its Members, we do not expect to be impacted by the 15 percent minimum tax because we do not expect to realize GAAP profits meeting or exceeding the required threshold. The IRA imposes a 1 percent excise tax on the fair market value of stock repurchases made by covered corporations after December 31, 2022. Since we do not issue stock, we are not impacted by the stock buyback excise tax. In addition, the IRA enacted many provisions intended to mitigate climate change by providing various sources of funding and tax credit incentives for investments designed to reduce greenhouse gas emissions. These provisions do not impact our current consolidated financial statements, but could affect future financial statements due to the impact of such investments. These provisions are subject to regulations to be released by the Department of the Treasury over time. We are evaluating these provisions and will continue to monitor developments and evaluate opportunities to utilize these incentives in the future.

NOTE 14 – LEASES

Leasing Arrangements as Lessee

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

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

We have lease agreements as lessee for the right to use various facilities and operational assets. Rent expense for all short-term and long-term operating leases was $0.6 million for the three months ended September 30, 2022 and $0.8 million for the comparable period in 2021. Rent expense for all short-term and long-term operating leases was $2.1 million for the nine months ended September 30, 2022 and $2.6 million for the comparable period in 2021. Rent expense is included in various categories of operating expenses on our consolidated statements of operations based on the type and purpose of the lease. As of September 30, 2022, there were no arrangements accounted for as finance leases.

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

	September 30, 2022	December 31, 2021
Operating leases		
Operating lease right-of-use assets	$ 8,864	$ 9,081
Less: Accumulated amortization	(2,185)	(1,552)
Net operating lease right-of-use assets	$ 6,679	$ 7,529
Operating lease liabilities - current	$ (390)	$ (491)
Operating lease liabilities - noncurrent	(1,327)	(1,622)
Total operating lease liabilities	$ (1,717)	$ (2,113)
Operating leases		
Weighted average remaining lease term (years)	7.6	7.6
Weighted average discount rate	3.85 %	3.79 %

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

Year 1	$ 294
Year 2	365
Year 3	255
Year 4	431
Year 5	94
Thereafter	553
Total lease payments	$ 1,992
Less imputed interest	(275)
Total	$ 1,717

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $1.7 million and $2.2 million for the three months ended September 30, 2022 and 2021, respectively, and $5.2 million and $5.7 million for the nine months ended September 30, 2022 and 2021, respectively, are included in other operating revenue on our consolidated statements of operations.

The lease arrangement with the Springerville Partnership is not reflected in our lease right right-of-use asset or liability balances as the associated revenues and expenses are eliminated in consolidation. See Note 16- Variable Interest Entities. However, as the non-controlling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded.

NOTE 15 – FAIR VALUE

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

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

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

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

In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. The assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified in Level 3.

Executive Benefit Restoration Plan Trust

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

	September 30, 2022		December 31, 2021	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 9,750	$ 8,884	$ 8,850	$ 8,640

Marketable Securities

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

	September 30, 2022		December 31, 2021	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 549	$ 473	$ 597	$ 598

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $50.5 million as of September 30, 2022 and $95.3 million as of December 31, 2021.

Debt

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

	September 30, 2022		December 31, 2021	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 2,990,849	$ 2,745,564	$ 3,214,427	$ 3,759,991

NOTE 16 – VARIABLE INTEREST ENTITIES

The following is a description of our financial interests in variable interest entities that we consider significant. This includes an entity for which we are determined to be the primary beneficiary and therefore consolidate.

Consolidated Variable Interest Entity

Springerville Partnership: We own a 51 percent equity interest, including the 1 percent general partner equity interest, in the Springerville Partnership, which is the 100 percent owner of Springerville Unit 3 Holding LLC ("Owner Lessor"). The Owner Lessor is the owner of the Springerville Unit 3. We, as general partner of the Springerville Partnership, have the full, exclusive and complete right, power and discretion to operate, manage and control the affairs of the Springerville Partnership and take certain actions necessary to maintain the Springerville Partnership in good standing without the consent of the limited partners. Additionally, the Owner Lessor has historically not demonstrated an ability to finance its activities without additional financial support. The financial support is provided by our remittance of lease payments in order to permit the Owner Lessor, the holder of the Springerville Unit 3 assets, to pay the debt obligations and equity returns of the Springerville Partnership. We have the primary risk (expense) exposure in operating the Springerville Unit 3 assets and are responsible for 100 percent of the operation, maintenance and capital expenditures of Springerville Unit 3 and the decisions related to those expenditures including budgeting, financing and dispatch of power. Based on all these facts, it was determined that we are the primary beneficiary of the Owner Lessor. Therefore, the Springerville Partnership and Owner Lessor have been consolidated by us.

Assets and liabilities of the Springerville Partnership that are included in our consolidated statements of financial position are as follows (dollars in thousands):

	September 30, 2022	December 31, 2021
Net electric plant	$ 726,532	$ 740,135
Noncontrolling interest	124,046	119,100
Long-term debt	255,117	300,220
Accrued interest	2,960	8,721

Our consolidated statements of operations include the following Springerville Partnership expenses for the three and nine months ended September 30, 2022 and 2021 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Depreciation, amortization and depletion	$ 4,534	$ 4,534	$ 13,603	$ 13,603
Interest	4,203	4,951	12,865	15,092

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

NOTE 17 – LEGAL

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

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

On March 20, 2020, FERC issued orders regarding our Jurisdictional PDO and our tariff filings. FERC's orders generally accepted our tariff filings and recognized that we became FERC jurisdictional on September 3, 2019, but did not make the tariffs retroactive to September 3, 2019. However, FERC specifically provided that no refunds are due on our Utility Member rates and our transmission service rates prior to March 26, 2020. FERC also did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered FPA section 206 proceedings to determine the justness and reasonableness of our rates and wholesale electric service contracts. On August 2, 2021, FERC approved our settlement agreement related to our Utility Member stated rate, as further discussed below. On March 7, 2022, FERC approved our settlement agreement related to our transmission service rates.

On August 28, 2020, FERC issued an order ("August 28 Order") on rehearing related to our Jurisdictional PDO which modified its March 20, 2020 decision on our Jurisdictional PDO by finding exclusive jurisdiction over our contract termination payments related to our Utility Members and preempting the jurisdiction of the COPUC as of September 3, 2019. On December 16, 2020, United Power filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court of Appeals") related to FERC's August 28 Order, 20-1256. On March 30, 2022, oral arguments occurred before the D.C. Circuit Court of Appeals regarding the Jurisdictional PDO. On September 16, 2022, the D.C. Circuit Court of Appeals denied United Power's petition related to FERC's August 28 Order and affirmed FERC's exclusive jurisdiction over our contract termination payments.

Petitions for review related to our tariff filings, including our Utility Member rates, have been filed with the D.C. Circuit Court of Appeals by other parties. On September 22, 2022, an order was issued by the court to hold all the cases before the D.C. Circuit Court of Appeals in abeyance other than related to the Jurisdictional PDO, directing the parties to file motions to govern future proceedings by December 21, 2022.

On August 2, 2021, FERC approved our settlement agreement related to our Utility Member stated rate, including our wholesale electric service contracts and certain of our Board policies filed with FERC. With the exception of four reserved issues contingent on United Power being a settling party, the settlement resolved all issues set for hearing and settlement procedures related to our Utility Member rates. The settlement provides for us to implement a two-stage, graduated reduction in the charges making up our Class A rate schedule of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from then current rates) thereafter until the date a new Class A wholesale rate schedule is approved by FERC and goes into effect. The settlement rates will remain in effect at least through May 31, 2023 and during such time period, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule. We have also agreed to file a new Class A rate schedule after May 31, 2023 and prior to September 1, 2023. During the moratorium, we have established a rate design committee to oversee the development of the new rate. Three of the reserved issues are related to the transmission component of our rates and the fourth relates to our community solar program. Additionally, with the exception of one reserved issue regarding transmission demand charges applicable to certain electric storage resources, each of the reserved issues will have prospective effect only, with the intent that any FERC rulings would be implemented in future rate filings.

A hearing on the four reserved issued occurred in March 2022 before an administrative law judge at FERC and an initial decision was issued by an administrative law judge on May 26, 2022. On the three reserved issues that will have a prospective effect only, the initial decision provides that we must also unbundle in our bills to our Utility Members our transmission costs, including ancillary services and other costs, and, in our future rate filings, we must directly assign to our Utility Members the costs of radial facilities that do not meet FERC's standards for being included in our rolled-in transmission demand rate. In addition, the initial decision provided that our Board policy for our community solar program was unduly discriminatory because it advantaged small Utility Members to the disadvantage of larger Utility Members. With regard to the reserved issue regarding transmission demand charges applicable to certain electric storage resources, the initial decision agreed with our Board policy of billing Utility Members for the transmission demand costs that includes all of a Utility Member's transmission demand, including such Utility Member's electric storage resource. On June 26, 2022, we, United Power, and certain other Utility Members filed exceptions to the initial decision. Because exceptions were taken to the initial decision, the initial decision and exceptions are now before the Commissioners of FERC for a decision on the four reserved issues.

It is not possible to predict the outcome of the four reserved issues related to our member rates docket. In addition, we cannot predict the outcome of any petitions for review filed with the D.C. Circuit Court of Appeals.

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

A hearing was held on May 18-20, 2020. On July 10, 2020, the administrative law judge issued a recommended decision, but the COPUC on its own motion stayed the recommended decision. On September 18, 2020, LPEA and United Power filed a Joint Motion to Lodge FERC’s August 28 Order, and asserted additional corporate law arguments related to the legality of our addition of Non-Utility Members. On October 22, 2020, the COPUC determined that COPUC’s jurisdiction over United Power and LPEA’s complaints was preempted by FERC, the COPUC does not have jurisdiction over corporate law matters, and dismissed both complaints without prejudice. On January 27, 2021, United Power filed a Writ for Certiorari or Judicial Review, an appeal, in the Denver County District Court, 2021CV30325, of the COPUC's decision to dismiss United Power's complaint. On February 17, 2021, the Denver County District Court granted our unopposed motion to intervene as a defendant in United Power’s appeal of the COPUC’s dismissal. United Power, the COPUC, and us have all filed respective briefs with the court. The court heard oral arguments on September 17, 2021. On November 3, 2022, United Power filed an unopposed motion for voluntary dismissal with prejudice of the Writ for Certiorari or Judicial Review. It is not possible to predict the outcome of this matter.

United Power's Adams District Court Complaint: On May 4, 2020, United Power filed a Complaint for Declaratory Judgement and Damages in the Adams County District Court, 2020CV30649, against us and our three Non-Utility Members. On July 2, 2021, the court granted United Power's motion to amend its May 2020 complaint to amend its claims as to our three Non-Utility Members and to add a claim that our addition of the Non-Utility Members violated Colorado law. On July 30, 2021, we filed a partial motion to dismiss a majority of United Power's claims. On July 30, 2021, the three Non-Utility Members filed a joint motion to dismiss all claims by United Power against the Non-Utility Members.

On March 23, 2022, the court issued an order regarding our and the Non-Utility Members’ motions to dismiss. The court dismissed some of the claims against us and the Non-Utility Members, including the civil conspiracy claim. After the dismissal, the remaining claims include seeking declaratory orders that the addition of the Non-Utility Members violated Colorado law, the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void, and the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula do not apply to United Power and are void, and that we have breached the wholesale electric service contract with United Power.

On April 6, 2022, we and each Non-Utility Member filed their respective answers to the first amended complaint denying that United Power is entitled to any relief and requesting the court enter judgment of dismissal. We also asserted counterclaims against United Power, and relief from United Power’s breach of our Bylaws and declaratory judgement that the April 2019 Bylaws amendment and the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula are valid. On April 27, 2022, United Power filed a reply to our counterclaims asserting that we are not entitled to any relief on our counterclaims. A jury trial is scheduled for June 2023. In the initial disclosures from United Power, United Power asserts that its damages in 2020 and 2021 exceed $87 million and United Power anticipates damages of $41 million in 2022 and $43 million each year thereafter that it remains a Utility Member of us. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

TAPP Complaint: On September 24, 2021, TransAmerican Power Products, Inc. (“TAPP”) filed a complaint in Adams County District Court, 2021CV31089, against us alleging breach of contract and breach of implied covenant of good faith and fair dealing related to an invoice for TAPP’s supply of materials for a transmission project. TAPP seeks damages of approximately $3 million. On November 9, 2021, we filed an answer and counterclaims against TAPP disputing any amount is owed to TAPP and seeking damages for TAPP's breach of contract. In October 2022, we reached a settlement with TAPP on this matter without us incurring any liability and the court granted the parties motion to dismiss the matter with prejudice.

Basin Complaint: On December 17, 2021, Basin filed a complaint with the United States District Court District of North Dakota Eastern Division, 3:21-cv-00220-PDW-ARS, against us alleging that the filing of our modified contract termination payment tariff filed with FERC on September 1, 2021 constitutes a breach of our wholesale power contract with Basin for the Eastern Interconnection. On February 28, 2022, Basin filed a first amended complaint adding a new claim for anticipatory breach of contract. Basin seeks, among other things, for the court to require us to amend our modified contract termination payment tariff to exclude our Eastern Interconnection Utility Members. On March 29, 2022, we filed a motion to dismiss Basin’s first amended complaint. On October 31, 2022, the court granted our motion and dismissed Basin's first amended complaint without prejudice.

FERC - Market Based Rate Authority: On December 27, 2021, we submitted to FERC our triennial market power update for the Southwest and Northwest regions in support of our continued authority to sell energy, capacity, and ancillary services at market-based rates in both the Southwest and Northwest regions. Our filing reflected that we pass the supplier indicative screens in the Public Service Company of Colorado (“PSCo”), Public Service Company of New Mexico (“PNM”), and WACM balancing authority areas and the wholesale market share screens in the PSCo and PNM balancing authority areas, but fail the wholesale market share indicative screen in the WACM balancing authority area in all seasons. Due to such failure, on February 28, 2022, FERC instituted a FPA section 206 proceeding to determine whether our market-based rate authority in the WACM balancing authority area remains just and reasonable and established a refund effective date of March 7, 2022, for market-based sales after such date. FERC issued a show cause order as to why FERC should not revoke our market-based rate authority in the WACM balancing authority area.

On April 29, 2022, we filed a response to the show cause order. FERC issued a decision on September 22, 2022 that revoked our market-based rate authorization in the WACM balancing authority area. Such revocation means that we cannot sell power in the WACM balancing authority area to non-members at bilaterally negotiated “market-based” rates. The FERC order instead requires us to file, within 30 days of the order, a tariff for cost-based rates applicable to non-member sales in WACM that would otherwise have been made under our market-based rate tariff. The order further requires us to refund any revenue from power sales in the WACM balancing authority area to non-members on or after March 7, 2022 in excess of the cost-based rates, and submit a refund report within 30 days of the order. On October 7, 2022, FERC granted our motion to extend the deadline until December 21, 2022 to make the above referenced filings. Based upon the FERC order requiring us to refund certain revenue from power sales in the WACM balancing authority area, in the third quarter of 2022, we accrued $2 million as a preliminary estimate of the amount to be refunded. It is not presently possible to calculate the exact amount of refunds that may be owed since March 7, 2022 as the cost-based rates is under development and it is not possible to predict the outcome of our cost-based rates tariff filing.

Energy Sales - Soft-Cap: In August 2020, we made certain energy sales to third parties in excess of the soft-cap price for short-term, spot market sales of $1,000 per megawatt hour established by the Western Electricity Coordinating Council. On October 7, 2020, we filed a report with FERC justifying the sales above the soft-cap and we did not recognize the revenue for the energy sales in excess of the soft-cap, EL21-65-000. Based upon additional guidance from FERC, we filed a supplemental report on July 19, 2021. On May 20, 2022, FERC issued an order directing us to refund only certain amounts of the energy sales revenue in excess of the soft-cap. Based upon the FERC order, in the second quarter of 2022, we recognized approximately $2.9 million in excess of the soft-cap and refunded $0.4 million to a third party. On July 22, 2022, the California Public Utilities Commission filed a petition for review with the DC Circuit Court of Appeals of FERC’s May 20, 2022 order. On August 18, 2022, we filed a motion to intervene with the DC Circuit Court of Appeals and an order granting said motion was issued on September 6, 2022. On August 25, 2022, FERC filed an unopposed motion to hold the case in abeyance. On September 14, 2022, the court issued an order to hold the proceedings in abeyance and directed parties to file motions to govern future proceedings by November 23, 2022. It is not possible to predict the outcome of this matter or whether we will be required to refund any additional amounts to third parties.

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

Overview

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

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

We supply and transmit our Utility Members’ electric power requirements through a portfolio of resources, including generation and transmission facilities, long term purchase contracts and short term energy purchases. We own, lease, have undivided percentage interests in, or long-term purchase contracts with respect to various generating facilities. Our diverse generation portfolio provides us with maximum available power of 4,319 MWs, of which approximately 1,366 MWs comes from renewables.

We sold 14.1 million MWhs for the nine months ended September 30, 2022, of which 89.5 percent was to Utility Members. Total revenue from electric sales was $1.041 billion for the nine months ended September 30, 2022 of which 89.4 percent was from Utility Member sales. Our results for the nine months ended September 30, 2022 were primarily impacted by higher temperatures and drought conditions, which resulted in increased energy demand, increased expenses and rate stabilization measures.

- Utility Member electric sales increased $33.7 million, or 3.8 percent, primarily due to higher sales volume as loads return to pre-pandemic levels and drought conditions in the West created greater demand for irrigation and higher temperatures resulted in increased cooling needs.
- Non-member electric sales increased $34.2 million, or 45.1 percent, primarily due to higher long-term and short-term market sales during the nine month period ended September 30, 2022.
- Purchased power expense increased $35.1 million, or 12.3 percent, primarily due to coal transportation constraints at a certain generating facility that resulted in reduced generation from that facility and outages at certain generating facilities both of which resulted in higher short-term purchases of power during 2022.
- Fuel expense increased $42.7 million, or 23.4 percent, primarily due to higher natural gas prices resulting from increased demand and constraints on supply resulting from market conditions, along with higher transportation costs for coal.
- Depreciation, amortization and depletion expense decreased $10.9 million, or 7.5 percent, primarily due to revisions to asset retirement obligations related to the South Taylor pit at the Colowyo Mine during the prior year.
- Other operating expenses increased $45.2 million primarily due to the recording of an additional environmental obligation of $44.9 million related to revised cost estimates at New Horizon Mine.

Our Bylaws and Wholesale Electric Service Contracts

Our Bylaws require each Utility Member, unless otherwise specified in a written agreement or the terms of the Bylaws, to purchase from us electric power and energy as provided in the Utility Member's contract with us. This contract is the wholesale electric service contract with each Utility Member, which is an all-requirements contract. Each wholesale electric service contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive, at least 95 percent of its electric power requirements from us. Our wholesale electric service contracts with our 42 Utility Members extend through 2050. Each Utility Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Utility Member. As of September 30, 2022, 21 Utility Members have enrolled in this program with capacity totaling approximately 145 MWs of which 129 MWs are in operation.

Pursuant to our wholesale electric service contracts with our Utility Members, we convened a contract committee in 2019 and 2020, consisting of a representative from each Utility Member, to review the wholesale electric service contracts and to discuss alternative contracts for our Utility Members, including partial requirements contracts. Upon recommendations from the contract committee, our Board approved a community solar program, a partial requirements structure, including a buy-down payment methodology, and a methodology to calculate a contract termination payment. For further information see "Item 1 – BUSINESS – MEMBERS" in our annual report on Form 10-K for the year ended December 31, 2021.

Under the new partial requirements membership construct, Utility Members can request to self-supply up to approximately 50 percent of their load requirements, subject to availability in the open season, in addition to the current 5 percent self-supply provision under the wholesale electric service contract and the community solar program. During our initial "open season" partial requirements nomination period that was completed in May 2021, three Utility Members were allocated an aggregate of 203 MWs of self-supply out of an available pool of 300 MWs. In January 2022, our Board approved an extension of the initial open season to offer the remaining 97 MWs of the 300 MWs of self-supply to the Utility Members who did not participate in 2021. During our extension of the initial "open season" partial requirements nomination period that was completed in May 2022, three additional Utility Members were allocated an aggregate of 97 MWs of self-supply. A total of six Utility Members have been allocated an aggregate of 300 MWs of self-supply. No Utility Member has executed a partial requirements contract to become a Class B member.

The Utility Members that choose the partial requirements option will be obligated to make a buy-down payment to us. Our Board-approved buy-down payment methodology for a Class A member to become a Class B member was accepted by FERC in 2020, subject to refund. FERC referred it to FERC's hearing and settlement judge procedures. On April 28, 2022, we filed a proposed settlement agreement for approval with FERC related to our buy-down payment methodology. The proposed settlement agreement resolves all issues set for hearing and settlement procedures related to our buy-down payment methodology. Virtually all of the parties to the proceeding either support or do not oppose the resolution of the proceeding related to the buy-down payment methodology. Only United Power filed comments opposing the proposed settlement agreement. The three Utility Members allocated self-supply during the initial "open season" are parties to the settlement. The settlement agreement resolves the level of the buy-down payment that a partial requirements Utility Member would pay us, and certain of the commercial terms and operational considerations applicable to the Utility Members that intend to become Class B partial requirements members. Class B members will continue to pay our Class A rate for load served by us and continue to purchase full-requirements transmission service from us. On July 12, 2022, the FERC settlement judge filed a report of contested settlement and stated the settlement is now before the commissioners at FERC for consideration.

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. In September 2021, we filed with FERC a modified contract termination payment methodology tariff. The modified contract termination payment methodology is designed to protect the financial interests of our remaining Utility Members if a Utility Member elects to withdraw from membership in us. Our September 2021 tariff filing includes requirements for a two-year notice and the payment of a contract termination payment to us. In simple terms, our modified contract termination payment amount is the greater of (i) the withdrawing Utility Member's debt covenant obligation, and (ii) the projected revenue the withdrawing Utility Member contractually agreed to pay over the remaining term of its wholesale electric service contract, less certain offsetting revenues we could earn by reselling the withdrawing Utility Member's share of energy and capacity and the net present value of the withdrawing Utility Member's patronage capital. The Utility Member's debt covenant obligation is its *pro rata* share of our total debt and other obligations. In October 2021, FERC accepted our modified contract termination payment methodology, effective November 1, 2021, subject to refund. FERC set the matter for hearing and instituted a concurrent FPA section 206 proceeding to determine the justness and reasonableness of our modified methodology.

A hearing on our modified contract termination payment methodology occurred in May 2022 before an administrative law judge at FERC. We, United Power, certain of our Utility Members, other parties, and FERC trial staff all presented different contract termination payment methodologies or adjustments thereto. On September 29, 2022, the administrative law judge issued an initial decision, which determined that the different contract termination payment methodologies by United Power, certain of our other Utility Members, and us were not just and reasonable. The administrative law judge endorsed the FERC trial staff methodology, with significant adjustments suggested by us. The administrative law judge's initial decision favorably discusses the concept of rate-neutrality to our remaining Utility Members and stated that the FERC trial staff's proposal, with our recommended changes, "appears to achieve an exit fee close to that of" our debt covenant obligation set forth in our contract termination payment methodology tariff. While the judge's initial decision does not include a contract termination payment number, we filed in March 2022 with FERC that United Power's debt covenant obligations is $736.4 million. On October 31, 2022, we, United Power, certain other Utility Members, and other parties filed exceptions to the initial decision. Because exceptions were taken to the initial decision, the initial decision and exceptions will be before the Commissioners of

FERC for a decision. For further information see "Item 1 – BUSINESS – MEMBERS - Relationship with Members" in our annual report on Form 10-K for the year ended December 31, 2021.

Three of our Utility Members, in December 2021, provided us conditional notices of their intent to withdraw from membership in us, including United Power and Northwest Rural Public Power District, with a January 1, 2024 withdrawal effective date. We filed certain answers to these conditional notices with FERC explaining that conditional notices are defective under the contract termination payment tariff and therefore a nullity. On April 21, 2022, FERC issued an order agreeing with our position that conditional notices are not permitted under our contract termination payment tariff and the conditional notices are invalid.

On April 29, 2022, both United Power and Northwest Rural Public Power District provided us notices to withdraw from membership in us, with a May 1, 2024 withdrawal effective date.

In July 2021, United Power's first amended complaint for declaratory judgement and damages against us and our Non-Utility Members was deemed filed alleging, among other things, that the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void and that we have breached our wholesale electric service contract with United Power. The first amended complaint also asserts that our addition of the Non-Utility Members violated Colorado law. In March 2022, the court dismissed some of the claims against us in response to our July 2021 partial motion for summary judgement. In April 2022, we filed our answer to the remaining claims. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

Responsible Energy Plan and Colorado Electric Resource Plan

Responsible Energy Plan

In July 2019, our Board established that we would pursue a transition to a cleaner energy portfolio by developing a Responsible Energy Plan. In January 2020, we released our Responsible Energy Plan. With our Responsible Energy Plan, we are implementing a clean energy transition while being responsible to our employees, Members, communities, and environment. The plan was developed with input from our Board, our Utility Members and external stakeholders. Our plan is dynamic and will change as Utility Members' needs change, new technologies become available and market conditions evolve. Over the past two years, we and our Utility Members have made great strides implementing the plan, which has allowed us to set new goals beyond those identified in January 2020. Some of the highlights of the Responsible Energy Plan include:

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

For further information regarding our Responsible Energy Plan, see "Item 1 – BUSINESS — MEMBERS – Responsible Energy Plan" in our annual report on Form 10-K for the year ended December 31, 2021.

Colorado Electric Resource Plan

In December 2020, we filed our first Phase I Electric Resource Plan under the COPUC rules related to electric resource plans, which contained our Preferred Plan. In September 2021, we submitted to the COPUC our Revised Preferred Plan in connection with Phase I of our 2020 Electric Resource Plan that modeled the addition of 2,050 MWs of additional renewable resources and more than 200 MWs of electric storage during the resource acquisition period of 2021 to 2030. In January 2022, we reached a comprehensive settlement agreement that was filed with the COPUC for approval. On March 28, 2022, the administrative law judge for the COPUC recommended approval of the settlement agreement and the approval became effective on April 18, 2022. The settlement agreement sets emissions reduction targets for our wholesale electricity sales in Colorado as follows: at least 26 percent in 2025, 36 percent in 2026, 46 percent in 2027, and 80 percent in 2030, with respect to the verified 2005 baseline. For further information, see "Item 1 – BUSINESS — POWER SUPPLY RESOURCES – Resource Planning" in our annual report on Form 10-K for the year ended December 31, 2021.

With the settlement agreement approved, we began Phase II of our 2020 Electric Resource Plan and issued in May 2022 a request for proposal of capacity and energy bids, with a focus on projects that support emissions reductions. These projects would be scheduled to come online in 2025 and 2026. The bidding process closed in September 2022. In October 2022, we filed our 30-day report with the COPUC disclosing that we received 274 individual eligible bid proposals (156 total projects) from bidders. We are currently doing portfolio modeling and we expect to file in early 2023 our implementation report with the COPUC.

On April 1, 2022, we made a filing with the COPUC for the retirement of our 85 MW natural-gas, combined-cycle Rifle Generating Station. On September 9, 2022, the COPUC issued a decision approving our filing and our Rifle Generating Station was retired on September 30, 2022.

Critical Accounting Policies

The preparation of our financial statements in conformity with GAAP requires that our management make estimates and assumptions that affect the amounts reported in our consolidated financial statements. We base these estimates and assumptions on information available as of the date of the financial statements and they are not necessarily indicative of the results to be expected for the year. As of September 30, 2022, there were no material changes in our critical accounting policies as disclosed in our annual report on Form 10-K for the year ended December 31, 2021.

Factors Affecting Results

Master Indenture

As of September 30, 2022, we had approximately $2.7 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Our Master Indenture requires us to establish rates annually that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis and permits us to incur additional secured obligations as long as, after giving effect to the additional secured obligation, we will continue to meet the DSR requirement on both a historical and pro forma basis. Our Master Indenture also requires us to maintain an ECR of at least 18 percent at the end of each fiscal year. Pursuant to our Master Indenture, DSR and ECR are calculated based on unconsolidated Tri-State financials and calculated in accordance with the system of accounts proscribed by FERC, not GAAP.

Margins and Patronage Capital

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

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

Pursuant to our Board Policy for Financial Goals and Capital Credits, we have historically set rates to achieve a DSR and ECR in excess of the requirements under our Master Indenture in order to mitigate the risk of potential negative variances between budgeted margins and actual margins. This policy establishes a goal of our Board on an annual or quarterly basis to either defer revenues and incomes as a regulatory liability or recognize previously deferred revenues and incomes (as available) in an amount that will result in a DSR equal to a DSR goal for the applicable year as set forth in the policy. As allowed by our Bylaws, the deferral or recognition of previously deferred revenues and income is for the purpose of stabilizing margins and rate stabilization measures to limit rate increases from year to year. This policy, subject to change by our Board, originally sets a 2022 DSR goal of 1.195 for the twelve months ended December 31, 2022 and a 2022 consolidated equity to capitalization ratio goal of 24.0 percent as of December 31, 2022. In October 2022, our Board reduced the 2022 DSR goal to reduce the amount of previously deferred membership withdrawal income needed to be recognized for rate stabilization for 2022. This lower 2022 DSR goal will result in lower margins for 2022, but is expected to meet the requirements under our Master Indenture of 1.10. In addition, our 2022 consolidated equity to capitalization ratio, which goal remains unchanged, is expected to exceed the financial goal of 24.0 percent as of December 31, 2022. Our Board may elect to change the DSR or consolidated equity to capitalization ratio goal in future years.

Rates and Regulation

On September 3, 2019, we became FERC jurisdictional for our Utility Member rates, transmission service, and our market based rates. In December 2019, we filed with FERC our tariff filings, including our stated rate cost of service filing, market based rate authorization, and transmission OATT. In March 2020, FERC issued orders generally accepting our tariff filings, subject to refund for sales after March 26, 2020. FERC did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered FPA section 206 proceedings to determine the justness and reasonableness of our rates, including our Class A wholesale rate schedule (A-40) referenced below, and wholesale electric service contracts. On August 2, 2021, FERC approved our settlement agreement related to our Utility Member stated rate that provides for us to implement a two-stage, graduated reduction in the charges making up our A-40 rate of two percent starting from March 1, 2021 until the first anniversary and four percent reduction (additional two percent reduction from then current rates) on March 1, 2022 until the date a new Class A wholesale rate schedule goes into effect. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

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

Revenues from electric power sales to our Utility Members are primarily from our Class A wholesale rate schedule filed with FERC. In 2021 and 2022, our Class A rate schedule (A-40) for electric power sales to our Utility Members consist of three billing components: an energy rate and two demand rates. Utility Member rates for energy and demand are set by our Board, consistent with the provision of reliable cost-based supply of electricity over the long term to our Utility Members. Energy is the physical electricity delivered to our Utility Members. The energy rate was billed based upon a price per kWh of physical energy delivered and the two demand rates (a generation demand and a transmission/delivery demand) were both billed based on the Utility Member’s highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays.

Our Class A rate schedule (A-40) was filed at FERC as a “stated rate.” While our Board still has authority to determine our rates, those rates, including any change to the rate or rate structure, must be approved by FERC subject to outside comments. As part of the FERC approved settlement agreement, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule, at least through May 31, 2023. A rate design committee consisting of a representative from each Utility Member is working on the development of a new rate to our Utility Members.

On September 22, 2022, FERC issued an order that revoked our market-based rate authorization in the WACM balancing authority area. Such revocation means that we cannot sell power in the WACM balancing authority area to non-members at bilaterally negotiated “market-based” rates. The FERC order instead requires us to file, within 30 days of the order, a tariff for cost-based rates applicable to non-member sales in WACM that would otherwise have been made under our market-based rate tariff. The order further requires us to refund any revenue from power sales in the WACM balancing authority area to non-members on or after March 7, 2022 in excess of the cost-based rates, and submit a refund report within 30 days of the order. On October 7, 2022, FERC granted our motion to extend the deadline until December 21, 2022 to make the above referenced filings. FERC's order also re-affirmed our market based rate authority in the Public Service Company of Colorado and Public Service Company of New Mexico balancing authority area. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

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

Tax Status

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

Results of Operations

General

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

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

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

Impacts of Supply Chain and Inflation

Our ability to meet our Utility Members' electric power requirements and complete our capital projects are dependent on maintaining an efficient supply chain. The procurement and delivery of materials and equipment have been impacted by the current domestic and global supply chain disruptions. We are experiencing shortages of critical items and longer lead-times on the procurement of certain materials and equipment, along with interruptions in production and shipping. Supply chain disruptions have contributed to higher prices for materials and equipment. We are also experiencing increased fuel costs for natural gas and costs for transportation of coal. We continue to monitor and are currently evaluating potential impacts to our operations and estimated capital expenditures and timing of projects related to inflationary pressures and supply chain disruptions.

We have several long-term solar power purchase agreements that were expected to commence commercial operation in 2023. Some developers have indicated they are experiencing difficulties due to supply chain issues and the United States Department of Commerce anti-circumvention investigation. We have agreed to allow additional flexibility for these projects, including extending the anticipated commercial operation dates to 2024.

Three Months Ended September 30, 2022 Compared to Three Months Ended September 30, 2021

Operating Revenues

Our operating revenues are primarily derived from electric power sales to our Utility Members and non-member purchasers. Other operating revenue consists primarily of wheeling, transmission, and coal sales. Other operating revenue also includes revenue we receive from certain of our Non-Utility Members. The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the three months ended September 30, 2022 and 2021 (dollars in thousands):

	Three Months Ended September 30,		Period-to-period Change	
	2022	2021	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 362,442	$ 350,344	$ 12,098	3.5 %
Non-member electric sales	55,669	35,876	19,793	55.2 %
Rate stabilization	32,950	8,575	24,375	284.3 %
Provision for rate refunds	(2,039)	—	(2,039)	(100.0)%
Other	16,971	21,068	(4,097)	(19.4)%
Total operating revenues	$ 465,993	$ 415,863	$ 50,130	12.1 %
Energy sales (in MWh):				
Utility Member electric sales	4,870,701	4,645,489	225,212	4.8 %
Non-member electric sales	614,436	560,066	54,370	9.7 %
	5,485,137	5,205,555	279,582	5.4 %

- Utility Member electric sales revenue increased primarily due to higher sales volume as loads continue a return to pre-pandemic usage levels and drought conditions in the West created greater demand for irrigation and higher temperatures resulted in increased cooling needs.
- Non-member electric sales increased primarily due to higher long-term and short-term market sales. Long-term sales increased 10,588 MWhs, or 5.8 percent, to 191,869 MWhs for the three months ended September 30, 2022 compared to 181,281 MWhs for the same period in 2021. The increase in long-term sales was due to higher sales from Springerville Generating Station to Salt River Project. Short-term market sales increased 43,782 MWhs, or 11.6 percent, to 422,567 MWhs for the three months ended September 30, 2022 compared to 378,785 MWhs for the same period in 2021. The average price for short-term market sales was 55.0 percent higher during the three months ended September 30, 2022 compared to the same period in 2021.
- In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized $33.0 million of previously deferred membership withdrawal income during the three months ended September 30, 2022 compared to $8.6 million of previously deferred non-member electric sales revenue during the same period in 2021 as part of our rate stabilization measures. In order to meet our revised 2022 financial goals, we still expect to recognize additional previously deferred membership withdrawal income during the remainder of 2022.
- During the three months ended September 30, 2022, an accrual was recorded in the amount of $2.0 million related to the preliminary estimate of the amount to be refunded from power sales in the WACM balancing authority area due to FERC's revocation of our market-based rate authority in the WACM balancing authority area. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

Operating Expenses

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

The following is a summary of the components of our operating expenses for the three months ended September 30, 2022 and 2021 (dollars in thousands):

	Three Months Ended September 30,		Period-to-period Change	
	2022	2021	Amount	Percent
Operating expenses				
Purchased power	$ 128,202	$ 112,540	$ 15,662	13.9 %
Fuel	94,770	76,332	18,438	24.2 %
Production	40,045	41,543	(1,498)	(3.6)%
Transmission	47,054	50,152	(3,098)	(6.2)%
General and administrative	18,658	15,916	2,742	17.2 %
Depreciation, amortization and depletion	46,604	44,990	1,614	3.6 %
Coal mining	1,814	1,492	322	21.6 %
Other	2,288	1,562	726	46.5 %
Total operating expenses	$ 379,435	$ 344,527	$ 34,908	10.1 %

- Purchased power expense increased primarily due to an increase of 189,069 MWhs, or 8.0 percent, purchased during the three months ended September 30, 2022 compared to the same period in 2021. Increased purchases were primarily due to coal transportation constraints at a certain generating facility that resulted in reduced generation from that facility and outages at certain other generating facilities both of which resulted in higher short-term purchases of power during 2022. Additionally, the average price was 6.1 percent higher during the three months ended September 30, 2022 compared to the same period in 2021.
- Fuel expense was higher primarily due to an increase of 50.2 percent in the average cost of natural gas prices for the three months ended September 30, 2022 compared to the same period in 2021 as a result of increased demand and constraints on supply as a result of market conditions. Additionally, fuel expense was higher due to a 193,221 MWh, or 7.5 percent, increase in generation by our coal-fired generating facilities and higher transportation costs for coal.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Operating Revenues

The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the nine months ended September 30, 2022 and 2021 (dollars in thousands):

	Nine Months Ended September 30,		Period-to-period Change	
	2022	2021	Amount	Percent
Operating revenues				
Utility Member electric sales	$ 931,257	$ 897,587	$ 33,670	3.8 %
Non-member electric sales	110,029	75,808	34,221	45.1 %
Rate stabilization	58,295	49,365	8,930	18.1 %
Provision for rate refunds	759	(6,403)	7,162	(111.9)%
Other	42,817	51,780	(8,963)	(17.3)%
Total operating revenues	1,143,157	1,068,137	$ 75,020	7.0 %
Energy sales (in MWh):				
Utility Member electric sales	12,585,009	12,014,631	570,378	4.7 %
Non-member electric sales	1,469,305	1,179,076	290,229	24.6 %
	14,054,314	13,193,707	860,607	6.5 %

- Utility Member electric sales revenue increased primarily due to higher sales volume as loads continue a return to pre-pandemic usage levels and drought conditions in the West created greater demand for irrigation and higher temperatures resulted in increased cooling needs.

- Non-member electric sales increased primarily due to higher long-term and short-term market sales. Long-term sales increased 141,443 MWhs, or 37.0 percent, to 523,587 MWhs for the nine months ended September 30, 2022 compared to 382,144 MWhs for the same period in 2021. The increase in long-term sales was due to higher sales from Springerville Generating Station to Salt River Project. Short-term market sales increased 148,786 MWhs, or 18.7 percent, to 945,718 MWhs for the nine months ended September 30, 2022 compared to 796,932 MWhs for the same period in 2021. The average price for short-term market sales was 24.7 percent higher during the nine months ended September 30, 2022 compared to the same period in 2021.
- In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized $58.3 million of previously deferred membership withdrawal income during the nine months ended September 30, 2022 compared to $49.4 million of previously deferred non-member electric sales revenue during the same period in 2021. In order to meet our revised 2022 financial goals, we still expect to recognize additional previously deferred membership withdrawal income during the remainder of 2022.
- During the nine months ended September 30, 2022, an accrual was recorded in the amount of $2.0 million related to the preliminary estimate of the amount to be refunded from power sales in the WACM balancing authority area due to FERC's revocation of our market-based rate authority in the WACM balancing authority area. Such amount was offset by our recognition of a favorable accrual adjustment of $2.9 million related to the energy sales to third parties in excess of the soft-cap price for short-term, spot market sales. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information. During the nine months ended September 30, 2021, an accrual was recorded in the amount of $6.0 million related to a settlement agreement on our transmission service rates, including our OATT and annual transmission revenue requirements. On March 7, 2022, FERC approved this settlement agreement and refunds were subsequently issued.

Operating Expenses

The following is a summary of the components of our operating expenses for the nine months ended September 30, 2022 and 2021 (dollars in thousands):

	Nine Months Ended September 30,		Period-to-period Change	
	2022	2021	Amount	Percent
Operating expenses				
Purchased power	321,240	286,109	$ 35,131	12.3 %
Fuel	225,491	182,749	42,742	23.4 %
Production	128,095	135,285	(7,190)	(5.3)%
Transmission	136,289	136,771	(482)	(0.4)%
General and administrative	57,824	42,400	15,424	36.4 %
Depreciation, amortization and depletion	133,347	144,228	(10,881)	(7.5)%
Coal mining	7,189	3,999	3,190	79.8 %
Other	50,626	5,395	45,231	*
Total operating expenses	$ 1,060,101	$ 936,936	$ 123,165	13.1 %

* Calculation not meaningful

- Purchased power expense increased primarily due to an increase of 496,771 MWhs, or 7.8 percent, purchased during the nine months ended September 30, 2022 compared to the same period in 2021, primarily from our long-term renewable sources. Increased purchases were primarily due to coal transportation constraints at a certain generating facility that resulted in reduced generation from that facility and outages at certain generating facilities both of which resulted in higher short-term purchases of power during 2022. Additionally, the average price was 4.2 percent higher during the nine months ended September 30, 2022 compared to the same period in 2021.
- Fuel expense was higher primarily due to an increase of 43.8 percent in the average cost of natural gas prices for the nine months ended September 30, 2022 compared to the same period in 2021 resulting from increased demand and constraints on supply resulting from market conditions. Additionally, fuel expense was higher due to a 419,122 MWh, or 6.7 percent, increase in generation by our coal-fired generating facilities and higher transportation costs for coal.
- General and administrative expense increased primarily due to lower recoveries of general and administrative costs from joint project activities, an increase in outside professional services and an overall increase in expenses related to general and administration labor and benefits.

- Depreciation, amortization and depletion expense primarily decreased due to revisions to asset retirement obligation related to the South Taylor pit at the Colowyo Mine during the prior year.
- Other operating expenses increased primarily due to the recording of an additional environmental obligation of $44.9 million related to revised cost estimates at New Horizon Mine.

Financial Condition as of September 30, 2022 Compared to December 31, 2021

The principal changes in our financial condition from December 31, 2021 to September 30, 2022 were due to increases and decreases in the following:

Assets

- Restricted cash and investments-current increased $16.9 million to $17.4 million as of September 30, 2022 compared to $0.5 million as of December 31, 2021. The increase was due to $16.2 million that was deposited with our Master Indenture Trustee in September 2022 in advance of our October 1, 2022 First Mortgage Obligations, Series 2014B payment. In accordance with our Master Indenture, we are required to fund the trust account one day prior to debt service payments.
- Regulatory assets decreased $1.5 million to $664.2 million as of September 30, 2022 compared to $665.7 million as of December 31, 2021. The change in regulatory assets was primarily impacted by the recognition of additional asset retirement obligations of $26.4 million at the Escalante and Nucla Generating Stations during 2022 and the recognition of $3.7 million during 2022 related to the deferred impairment loss at Rifle Generating Station. These increases were partially offset by amortization of $32.6 million to depreciation, amortization and depletion expense and recovered from our Utility Members through rates.

Liabilities

- Long-term debt decreased $217.4 million, or 7.0 percent, to $2.884 billion as of September 30, 2022 compared to $3.102 billion as of December 31, 2021 and current maturities of long-term debt decreased $5.5 million, or 6.0 percent, to $87.5 million as of September 30, 2022 compared to $93.0 million as of December 31, 2021. The total decrease of $222.9 million was primarily due to debt payments of $223.6 million (principally $100.0 million for the First Mortgage Bonds, Series 2014E-1, $44.4 million for the Springerville certificates, $42.5 million of CoBank and CFC debt, and $20.0 million for the First Mortgage Bonds, Series 2016A). We repurchased and cancelled $136.7 million of our First Mortgage Bonds, Series 2014E-1 and our First Mortgage Bonds, Series 2016A with cash and short-term borrowings. See “Liquidity and Capital Resources” for more information on the tender offer.
- Short-term borrowings increased $214.5 million to $264.5 million as of September 30, 2022 compared to $50.0 million as of December 31, 2021. The increase was due to commercial paper activity during 2022 primarily related to early repurchase and cancellation of certain of our bonds.
- Accrued interest increased $17.1 million, or 66.5 percent, to $42.8 million as of September 30, 2022 compared to $25.7 million as of December 31, 2021. The increase was primarily due to accruals for interest that is due in the future of $106.1 million partially offset by interest payments of $89.0 million.
- Regulatory liabilities decreased $58.6 million, or 40.2 percent, to $87.4 million as of September 30, 2022 compared to $146.0 million as of December 31, 2021. The decrease was primarily due to the recognition of $58.3 million of previously deferred membership withdrawal income. In order to better align with our financial goals, we recognize deferred revenue and income on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2022.
- Asset retirement and environmental reclamation obligations increased $114.1 million, or 137.1 percent, to $197.4 million as of September 30, 2022 compared to $83.3 million as of December 31, 2021. The increase was due to the recording of an additional environmental obligation of $44.9 million related to revised cost estimates at New Horizon Mine, additional asset retirement obligations of $32.8 million related to an update in cost estimates at the Colowyo Mine and additional asset retirement obligations of $38.4 million related to an update in cost estimates for obligations related to our ponds, ash land fill and post-closure reclamation and monitoring at various generating facilities.

Liquidity and Capital Resources

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of short-term and long-term borrowings. As of September 30, 2022, we had $107.2 million in cash and cash equivalents. Our committed credit arrangement as of September 30, 2022 is as follows (dollars in thousands):

	Authorized Amount		Available September 30, 2022
2022 Revolving Credit Agreement	$ 520,000	(1)	$ 255,000

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

We have a secured 2022 Revolving Credit Agreement with aggregate commitments of $520 million. The 2022 Revolving Credit Agreement includes a swingline sublimit of $125 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million, of which $125 million of the swingline sublimit, $75 million of the letter of credit sublimit, and $235 million of the commercial paper back-up sublimit remained available as of September 30, 2022.

The 2022 Revolving Credit Agreement is secured under our Master Indenture and has a maturity date of April 25, 2027, unless extended as provided therein. Funds advanced under the 2022 Revolving Credit Agreement bear interest either at adjusted Term SOFR rates or alternative base rates, at our option. The adjusted Term SOFR rate is the Term SOFR rate for the term of the advance plus a margin (1.125 percent as of September 30, 2022) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (0.125 percent as of September 30, 2022) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00 percent, (b) the prime rate, and (c) the adjusted Term SOFR rate plus 1.00 percent and plus a margin (1.125 percent as of September 30, 2022) based on our credit ratings.

The 2022 Revolving Credit Agreement contains customary representations, warranties, covenants, events of default and acceleration, including financial DSR and ECR requirements in line with the covenants contained in our Master Indenture. A violation of these covenants would result in the inability to borrow under the facility.

Under our commercial paper program, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our 2022 Revolving Credit Agreement, which was $500 million as of September 30, 2022, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of September 30, 2022, we had $265 million of commercial paper outstanding (prior to netting discounts) and $235 million available on the commercial paper back-up sublimit.

On July 13, 2022, we announced cash tender offers to purchase for cash up to $100 million aggregate principal amount of our First Mortgage Bonds, Series 2014E-1 (due 2024), our First Mortgage Bonds, Series 2014E-2 (due 2044), and our First Mortgage Bonds, Series 2016A (due 2046). The early tender offer deadline was July 26, 2022 and $100 million principal amount of our Series 2014E-1 (due 2024) bonds were tendered and accepted. We paid a total of $100.2 million in aggregate for purchase of the bonds, including early tender payments. We paid for the purchase of the bonds with available cash and short-term borrowings.

In addition to the July 2022 tender offers, we have previously purchased our outstanding debt through cash purchases in open market purchases. In the future, we may from time to time purchase additional outstanding debt through cash purchases and/or exchanges for other securities, in open market purchases, privately negotiated transactions, additional tender offers, or otherwise and may continue to seek to retire or purchase our outstanding debt in the future. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. We are mindful of our debt and its maturities and we continually evaluate options to ensure that our balance sheet and capital structure is aligned with our business and the long-term health of our company.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, and the 2022 Revolving Credit Agreement.

Cash Flow

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

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Operating activities. Net cash provided by operating activities was $125.8 million for the nine months ended September 30, 2022 compared to $170.7 million for the same period in 2021, a decrease in net cash provided by operating activities of $44.9 million. The decrease in net cash provided by operating activities was impacted by an increase in purchased power expense, higher natural gas prices, timing of payment of trade payables and lower cash deposits related to interconnection customers.

Investing activities. Net cash used in investing activities was $88.6 million for the nine months ended September 30, 2022 compared to $99.1 million for the same period in 2021, a decrease in net cash used in investing activities of $10.5 million. The decrease in net cash used in investing activities was primarily due to timing of payments we made to operating agents of jointly owned facilities to fund our share of costs to be incurred under each project.

Financing activities. Net cash used in financing activities was $14.1 million for the nine months ended September 30, 2022 compared to $101.4 million for the same period in 2021, a decrease in net cash used in financing activities of $87.3 million. The decrease in net cash used in financing activities was primarily due commercial paper activity during 2022 principally related to early repurchase and cancellation of certain bonds partially offset by higher principal payments of long-term debt of $136.4 million. On July 28, 2022, we completed our cash tender offer to purchase $100.0 million of our First Mortgage Bonds, Series 2014 E-1 (due 2024).

Capital Expenditures

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility closures, facility costs, market factors and other items affecting our forecasts. After taking into account our Responsible Energy Plan, in the years 2022 through 2026, we forecast that we may invest approximately $877 million in new facilities and upgrades to our existing facilities.

Our actual capital expenditures depend on a variety of factors, including assumptions related to our Responsible Energy Plan and our Revised Preferred Plan in conjunction with Phase I of our 2020 Electric Resource Plan approved by the COPUC, Utility Member load growth, availability of necessary permits, regulatory changes, environmental requirements, construction delays and costs, supply chain issues, inflation, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

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

Changing Environmental Regulations

We are subject to extensive federal, state and local environmental requirements. These environmental laws, rules and regulations are complex and change frequently. The following is a recent development relating to environmental litigation that impacts us.

Collom Air Permit

In November 2019, the Collom air permit revision for the Collom pit at the Colowyo Mine was issued by CDPHE. In December 2019, the Center for Biological Diversity and Sierra Club filed a new case challenging the CDPHE's issuance of the Collom air permit revision. In October 2020, the judge issued an order affirming the CDPHE's issuance of the minor source construction air permit to Collom. The Center for Biological Diversity and Sierra Club appealed the decision to the Colorado Court of Appeals. In March 2022, the Colorado Court of Appeals affirmed the District Court's decision upholding the air permit for Collom. In May 2022, the Center for Biological Diversity and Sierra Club filed a Petition for Writ of Certiorari with the Colorado Supreme Court. We and the State of Colorado filed responses in opposition to the petition. In October 2022, the Colorado Supreme Court denied the Petition for Writ of Certiorari.

For further discussion regarding potential effects on our business from environmental regulations, see "Item 1 – BUSINESS — ENVIRONMENTAL REGULATION" and "Item 1 – RISK FACTORS" in our annual report on Form 10-K for the year ended December 31, 2021 and "Item 2 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS" in our quarterly report on Form 10-Q for the quarterly period ended June 30, 2022.

Rating Triggers

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

Our 2022 Revolving Credit Agreement includes a pricing grid related to the Term SOFR spread, commitment fee and letter of credit fees due under the facility. A downgrade of our senior secured ratings could result in an increase in each of these pricing components. We do not believe that any such increase would be significant or have a material adverse effect on our financial condition or our future results of operations.

We currently have contracts that require adequate assurance of performance. These include natural gas supply contracts and financial risk management contracts. Some of the contracts are directly tied to us maintaining investment grade credit ratings by S&P and Moody’s. We may enter into additional contracts which may contain similar adequate assurance requirements. If we are required to provide such adequate assurances, we do not believe the amounts will be significant or that they will have a material adverse effect on our financial condition or our future results of operations.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes to market risks during the most recent fiscal quarter from those reported in our annual report on Form 10-K for the year ended December 31, 2021.

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 Note 17 to the Unaudited Consolidated Financial Statements in Item 1.

Item 4. Mine Safety Disclosures

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

Item 6. Exhibits

Exhibit Number	Description of Exhibit
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Duane Highley (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Patrick L. Bridges (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Duane Highley (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Patrick L. Bridges (Principal Financial Officer).
95	Mine Safety Disclosure Exhibit.
101	XBRL Interactive Data File.

SIGNATURES

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

Tri-State Generation and Transmission Association, Inc.

Date: November 14, 2022

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

Date: November 14, 2022

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