DRIVING CHANGE

2021

TRI-STATE | ANNUAL REPORT

70 YEARS

TRI-STATE

Tri-State Generation and Transmission Association, Inc. is a not-for-profit cooperative power supplier. Our mission is to provide our member systems a reliable, affordable and responsible supply of electricity in accordance with cooperative principles.

Cooperative Strength

TIM RABON, TRI-STATE CHAIRMAN & OTERO COUNTY ELECTRIC COOPERATIVE TRUSTEE

"With the combined strength of Tri-State's members and the talents of its employees, Tri-State is well positioned to meet the changing needs of our members, resolve the differences between our members, and continue serving reliable, affordable and responsible power to communities across the West."

Letter from the Chairman

Driving change requires involvement from all who have a stake in the future direction of this association. And the beauty of our cooperative business model is that its structure allows for discussion, debate and a collective determination of that future direction. Each member is driven by the needs of those they serve, the consumers who count on the electricity we deliver. This means we may not always agree, but we've created an environment where everyone has a platform and is treated with respect.

In addition to having a voice around the board table, our members also have a voice at the Federal Energy Regulatory Commission (FERC), where members serving Colorado, Nebraska, New Mexico and Wyoming can all weigh in on the wholesale rate and contract decisions that impact our cooperative.

In 2021, we took up critical discussions related to the wholesale electric service contract and advanced flexible contract options that preserve the value of membership in Tri-State while enabling members to elect to self-supply a greater portion of their power.

Central to our mission, Tri-State has performed well for our members, maintaining reliability and advancing affordability, while making great strides to fulfill our responsibilities.

Through our Responsible Energy Plan, the board defined the priorities for Tri-State staff to focus on. And through the last two years, Tri-State has taken swift and steady action to implement that plan.

Notably, staff has advanced our clean energy transition while also delivering a 4% wholesale rate decrease and returning $10 million in patronage capital to the membership. The work continues, but the progress is commendable.

I'd like to conclude with a note of gratitude to my predecessor Rick Gordon. Rick's leadership and dedication, along with the engagement of our fellow directors and the efforts of Tri-State's talented staff, have helped to secure the strong position we are in today. Thank you to Rick for the guidance and to the board for trusting me to lead – it's humbling and a true honor.

Tim Rabon, Chairman

CHAIRMAN'S PRIORITIES

KEEP THE LIGHTS ON
Reliability is our cooperative's first job as we advance our focus on electricity affordability, increased flexibility and our changing generation portfolio.

BENEFIT ALL MEMBERS WITH OUR TRANSITION
As a member-owned association, our transition will benefit the entire membership, not just a few.

UPHOLD COOPERATIVE VALUES
Protect and defend the sanctity of the cooperative model.

CONTINUE OUR PROGRESS
The board supports Tri-State's transition and will ensure we continue forward even as we learn to navigate the challenges that arise.

Letter from the CEO

Transformations come with a starting point and an end goal, but some of the most interesting things happen somewhere in the middle. That's where we are. We aren't yet at our destination, but we're making swift progress in that direction.

In 2020, the Tri-State Board of Directors set ambitious goals in the Responsible Energy Plan, including deep emission reductions while maintaining reliability, expanding member flexibility and striving to reduce rates.

This past year we have experienced momentous action to bring us closer to achieving those goals. We started from a place of stability – meeting all our financial goals and maintaining consistent operational performance. From there, we have pushed forward and continued to raise the bar.

The following pages detail the progress we've made related to Reliability, Affordability, Flexibility and Responsibility, but to sum it up, in 2021 we delivered.

Reliability was achieved through collaboration among our teams and our members. We responded together through extreme weather events with a focus on limiting impact to our members. We also helped lay the foundation for a move toward increased participation in regional energy markets to better use our generation and transmission resources across the West.

Affordability was in the spotlight with cost reduction efforts supporting a 4% rate reduction that began in 2021 and was fully implemented in 2022.

Flexibility was increased through the active participation of our members, who developed policies to allow interested members to self-supply a greater portion of their energy.

Responsibility is woven throughout everything we do, but in 2021 it included the completion of two new wind projects; the advancement of initiatives around beneficial electrification, energy efficiency and electric vehicle infrastructure; and an ongoing focus on support for those communities impacted by the energy transition.

We've made this progress quickly and safely, while managing through the challenges of the pandemic. We have further to go, but we've gotten as far as we have because of the involvement of our board and members and the commitment of our employees. Our mission is strong, and our cooperative business model remains the best way to serve that mission.

Change brings challenges, but we're approaching it with our eyes and ears open. We're listening to our members, our employees, our supporters and our critics. We're defining the Tri-State of the future, and while it's not easy, it's some of the most worthwhile work I know.

Duane Highley, Chief Executive Officer

"We're defining the Tri-State of the future, and while it's not easy, it's some of the most worthwhile work I know."

Introduction

2021 was a year of driving forward changes that will set Tri-State up for long-term resilience and success. Starting from a stable foundation, we took necessary steps toward our future.

Tri-State's resources performed well through the standard seasonal fluctuations and when extreme weather tested the system. We also added two new renewable resources. Participation in organized markets and the advancement of efforts toward joining a western regional transmission organization positioned us for even greater reliability and affordability. Our cooperative met all financial goals and maintained investment-grade ratings, while we reduced our wholesale rate and year-over-year debt and returned patronage capital to members.

When our board outlined our Responsible Energy Plan, we knew where we would be focused, and the development of our integrated strategy map defines how we will get there and aligns staff actions. This map identifies member needs and corresponding goals, along with the priorities and actions we will take to achieve those goals. It also defines the values and employee focus that are critical to supporting our progress and our mission.

As we've approached our work, we've maintained our focus on safety, and through another year of the pandemic, key safety metrics remained better than industry averages.

To say we're driving change, we have to be able to prove it with action. That's what we've done in 2021, and it has set the momentum for the future.

NIYOL WIND, CO

Quick facts and financials

$1.4B
operating revenue

7.4¢/kWh
average member wholesale rate

145 MW
member renewable projects operating or under development

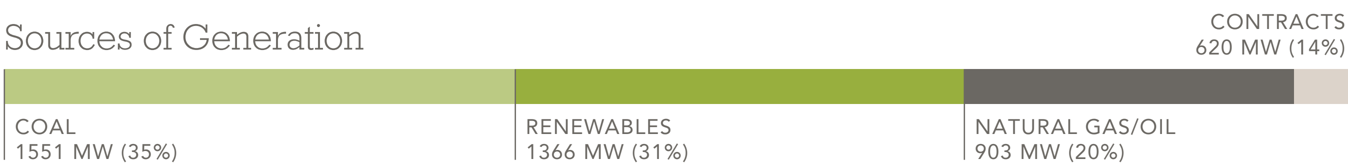
$26M
net margin, allocated as patronage capital in 2021

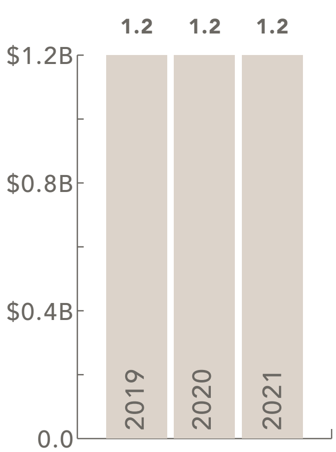
$10M
patronage capital returned to members in 2021

$4.9B
total assets

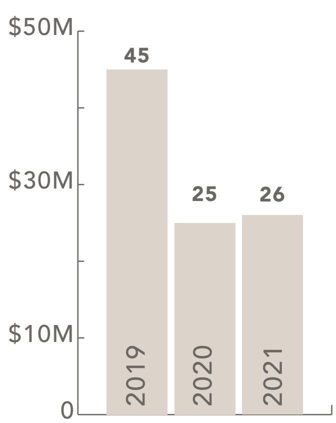
17.6M MWh Total Energy Sold

Sources of Generation

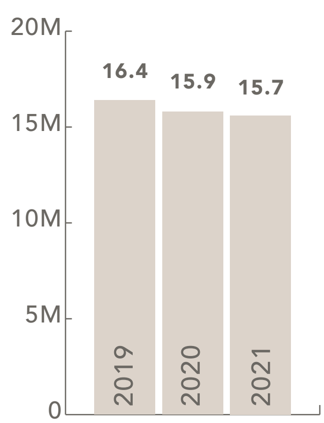




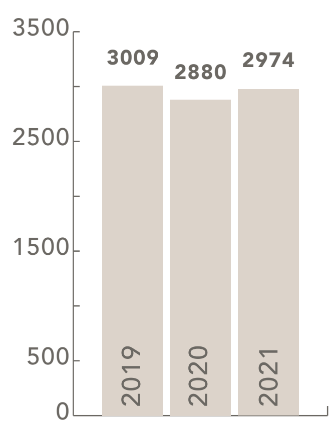
OPERATING EXPENSES



NET MARGIN



ENERGY SOLD TO MEMBERS (MWh)



MEMBER COINCIDENT PEAK DEMAND (MW)

Reliability

There's a reason reliability is the first thing we reference in our mission statement. When individuals, businesses and communities are counting on it, the power must be on.

For Tri-State, this means we have to ensure we have the power supply to meet our member requirements, we have to invest in the strength of our transmission system and we have to maintain all of our facilities so we can count on them to operate effectively. It's a constant process of measuring, evaluating, planning and responding. In 2021, we continued to deliver on our commitment to reliability:

TRANSMISSION SYSTEM IMPROVEMENTS
We improved transmission system reliability and capacity by completing $89M in capital additions and improvements, with several line and substation upgrades completed or underway. We also planned significant transmission system upgrades for eastern Colorado for completion later this decade to support the integration of future renewable projects.

ROBUST MAINTENANCE PROGRAM
In addition to ongoing maintenance on our transmission assets, we also completed a major maintenance outage on Craig Station Unit 3, improved J.M. Shafer Station's cold weather operational reliability and enhanced our Generation Performance Monitoring system for improved reliability and cost control.

RESOURCE PLANNING
We made significant progress on Phase I of our Colorado Electric Resource Plan with the input of more than two dozen parties and performed a generation siting study for future generation.

FUTURE GENERATION AND STORAGE TECHNOLOGIES
We initiated a study of the potential for Craig Station to support a 3,000 MWh molten salt storage project and responded to a Department of Energy Request for Information to propose using Craig Station as a site for a green hydrogen pilot project.

EXTREME WEATHER RESPONSE
During winter storm Uri, when challenged with record cold weather affecting much of the United States, our members' investment in Tri-State ensured that power was delivered reliably and affordably. Our diverse portfolio of resources and power contracts, our vast transmission network, and our participation in organized markets mitigated risks and enabled us to avoid any significant operational and financial issues.

Our dual-fuel combustion turbine generating facilities were able to switch to fuel oil when the price of natural gas spiked. The flexibility of these resources, the quality of our system overall and the collaboration of all Tri-State teams and member systems involved in this response were key to a successful outcome.

SECURITY AND PREPARATIONS
We made numerous improvements to increase physical security, system reliability and cybersecurity; and conducted security and disaster recovery emergency exercises including the North American Electric Reliability Corporation's (NERC) GridEx VI.


J.M. SHAFER STATION, CO

Affordability

The value of the reliable power we provide is further strengthened when member-consumers at the end of the line can afford their electricity bill. So when we think of how we spend each dollar to operate and maintain our system, we have that electricity consumer in mind. In 2021, we continued to deliver on our commitment to affordability:

RATE REDUCTIONS

We reached consensus with our members and other parties in Federal Energy Regulatory Commission (FERC) processes to reduce wholesale rates by 4%, implemented in 2021 and 2022, as we strive to further lower costs while we transition.

COST MANAGEMENT

Working with our employees and members, we've identified efficiencies and cost savings that place us on a path to maintain the stable wholesale rates and rate reductions we've been able to achieve over the past five years.

ORGANIZED MARKETS

We entered two energy imbalance markets and 80% of our load is now in an organized market as we work toward the greater reliability and affordability available of a regional transmission organization (RTO) in the Western Interconnect. These new energy imbalance markets will enable us to optimize resources regionally with our neighbors and more fully utilize regional transmission.

RATE ACCEPTANCE AT FERC

Our rates for wholesale power and transmission service have been accepted by the FERC, and in 2022 our members will work through a rate design committee as we prepare for a new wholesale rate filing in 2023.

"Morgan County REA is proud to be a cooperative member of an association that prioritizes reliability and rate stabilization. Not only have unchanged wholesale rates from Tri-State allowed MCREA to keep rates steady since 2016, Tri-State's recent wholesale rate reduction has actually allowed a rate decrease to be passed on to MCREA members, effective January 1, 2022."

– Rob Baranowski, Morgan County REA, Manager of Member Services

Responsibility

Responsibility has always been a part of how we approach our business – we're responsible for more than just keeping the lights on. We must do it with respect for the natural resources we share, the communities we and our members serve, and the employees we support. In 2021, we continued to deliver on our commitment to responsibility:

INCREASING CLEAN ENERGY

- In 2021, we completed two new wind projects, totaling 304 MW, with another 735 MW of solar projects scheduled for completion in 2023 and 2024.

- Over a third of the energy our members used this year came from clean sources as we work toward our goal of 50% by 2024. We filed a Revised Preferred Plan to our Colorado ERP, identifying a significant investment in over 2,000 MW of renewables and battery storage to increase our clean energy to approximately 4,000 MW by 2030, when 70% of the energy our members use is expected to come from clean energy.

COMMITTING TO COMMUNITIES AND EMPLOYEES

- We committed $5 million to four local economic development organizations to support economic and community transition following the 2020 retirement of Escalante Station in New Mexico.

- We worked with local and state leaders and other supportive partners to begin exploring opportunities to retain local employment and revenue in transitioning Colorado and New Mexico communities by co-locating hydrogen and other clean energy projects at power plant sites, including by responding to federal requests for information and grant funding opportunities.

- With research and community partners, we installed a container farm at the New Mexico State University Grants campus to support a study of the energy, water and sustainability impacts of indoor farming, as well as advance opportunities for workforce and economic development in the area.

REDUCING EMISSIONS

- Since 2017, we have decreased our coal capacity through the retirements of Nucla Station in Colorado and San Juan Generating Station and Escalante Station in New Mexico.

- We filed a Revised Preferred Plan to our Colorado ERP, identifying an 80% reduction in greenhouse gas emissions associated with wholesale electricity sales in Colorado by 2030, relative to a 2005 baseline.

EXTENDING CLEAN GRID BENEFITS

- Since its inception in 2020, our EV infrastructure program has supported member installation of 385 EV chargers, including four DC fast chargers and seven Level 2 public installations.

- Through our EV Experience Program, members logged almost 100,000 miles of EV ride-and-drives across their service areas.

- With our heat pump Quality Install program and rebates, we saw more than 576 air-source heat pumps installed – a 30% increase throughout our service area.

- We continued our support for the Beneficial Electrification League as a Foundational Sponsor and Advisory Board member and engaged with the Colorado chapter to advance installation of air-source heat pumps while continuing to develop interest in chapters in Nebraska, New Mexico and Wyoming.

We are adding 735 MW of upcoming renewable projects in 2023 and 2024

145 MW	Axial Basin Solar (2023) – Moffat County, CO
110 MW	Dolores Canyon Solar (2023) – Dolores County, CO
200 MW	Escalante Solar (2023) – McKinley County, NM
100 MW	Spanish Peaks Solar (2023) – Las Animas County, CO
40 MW	Spanish Peaks II Solar (2023) – Las Animas County, CO
140 MW	Coyote Gulch Solar (2024) – Montezuma County, CO

Flexibility

Electricity innovations are evolving every day, and our members desire the flexibility to take advantage of those innovations. For years our members have had the option to self-supply up to 5% of their power requirements, and many of them have taken advantage of that option.

Our members worked together to develop a more flexible wholesale contract option so they can self-supply more power than ever before, and we're working together to make it a reality. In 2021, we continued to deliver on our commitment to flexibility:

SELF-SUPPLY

We implemented new member-driven policies to allocate 300 MW of self-supply capacity, with three members nominating 203 MW to take a more active role in providing power in their communities, and we filed supportive policies with the FERC.

LOCAL RESOURCES

With the addition of a policy that supports community solar, members are pursuing additional projects, and we collaborated with a member to support development of a remote community's microgrid to promote resilience through local resources.

NEW CONTRACT OPTIONS

We continued to work with our members to advance options that create flexibility for members that desire it without raising costs for other members.

RED FEATHER LAKES, CO

RED FEATHER LAKES MICROGRID: PROMOTING RESILIENCE THROUGH LOCAL RESOURCES

Tri-State worked with member Poudre Valley Rural Electric Association (PVREA) to support a microgrid installation for the Red Feather Lakes community northwest of Fort Collins, Colorado.

Red Feather Lakes receives electricity by a single transmission line. The threat of extreme weather, car accidents on the curvy roads and wildfires all pose serious threats to the reliability of electricity for the small town. As a result, PVREA worked with the community, Tri-State and others to install a new energy storage device that, in conjunction with existing on-site resources, will serve certain buildings in the isolated area in the event of unanticipated transmission outages.

The microgrid was designed to provide power to critical facilities, including the fire station and library, which provide support and shelter to the community. The microgrid can maintain power for up to eight hours when other parts of the grid are temporarily unavailable, and it includes a 140 kW, 446 kWh Tesla Powerpack battery, 20 kW of solar photovoltaic, and a 130 kW propane generator.

"We are able to start learning what a microgrid does, what we can do with it and apply that knowledge to future projects."

– Jeff Wadsworth, president and CEO of PVREA

Culture at Tri-State

WITH ELDA DE LA PEÑA

You can't get from here to there without listening to those who got you where you are. Our members govern our co-op, but our talented employees know the intricacies of our business best, and they know how to push us to keep doing better, preparing our operations for the future.

Empowering transformation

In 2021, Tri-State further demonstrated our dedication to our employees through the addition of our Senior Vice President of People and Culture. This position reports directly to the CEO and enables greater advocacy at our executive level for employees across our cooperative.

What role do Tri-State employees play in the company's transformation?

A strong and engaged workforce is critical to Tri-State's success as we move toward our goals. Our employees care deeply about our mission and put our members first every day. We provide the tools and support necessary to develop and empower our employees, because their success becomes our success. We support a culture of cooperation, where all employees are encouraged to bring forward new ideas that support our mission. We listen, look forward, embrace change, and nurture an environment where we can all complete our work safely and effectively.

How does Tri-State incorporate the voice of employees as it makes decisions about the future of the business?

We provide a number of opportunities for employees to share their voices and ideas, because listening is such an incredibly important part of knowing where people are. By listening to our employees, we can identify what's going well and where there may be concerns to address.

In 2021, we really dug into the feedback we received through our employee engagement survey. Tri-State employees helped us identify the strengths in our culture and where there are challenges we can help them work through. We pulled together our Employee Advisory Committee to review the themes that came out of the survey and identify ways to support the positive trends we saw and find the opportunities where we can learn and improve.

At any time, employees can use our Employee Idea Program to submit a suggestion for improving our operational processes, systems, or even our culture. These ideas have resulted in a number of new programs, including our paid volunteer day and additional flexibility in work schedules and work locations. Our CEO, Duane Highley, also makes himself available to hear from all employees. He hosts regular all-employee town halls, where everyone is invited to ask questions.

How does Tri-State support a diverse, equitable and inclusive workplace?

As Tri-State is going through a transformation, we recognize the importance of embracing unique voices and being inclusive of ideas from all areas of the company. We want our employees to be invested in the Tri-State we're becoming.

In 2021, we launched a more formal Diversity, Equity and Inclusion (DEI) Program. All employees were invited to be part of a collaborative team that's looking at what DEI means at Tri-State. We know our program will evolve over time, but this diverse group has already identified ways our workplace can further develop into a place of inclusivity. We're providing education opportunities, and evaluating all our programs, policies and procedures to ensure they embody the philosophy of DEI.

OUR DIVERSITY, EQUITY AND INCLUSION STATEMENT

As Tri-State moves toward a sustainable future, we are also working toward a diverse, equitable and inclusive culture for our current and future employees. We are committed to providing a respectful, safe and welcoming atmosphere where all employees can have their unique ideas and experiences recognized.

Energy Management

WITH BRAD NEBERGALL

Tri-State has always managed its resources from a place of collaboration. Energy Management is the group that navigates the complexities of our owned generation, power purchase agreements, power markets and organized markets – optimizing the assets Tri-State owns by efficiently dispatching our resources and looking ahead to plan the resources needed for the future.

Working together to build momentum

In 2021, Tri-State continued to make progress in several foundational areas: two new wind projects came online, Tri-State joined two energy imbalance markets (EIM), took steps toward participation in a regional transmission organization (RTO) with its western load and conducted a highly collaborative process to develop our latest electric resource plan.

What are the benefits of participation in organized markets?

It's complex and expensive to operate the electric grid, especially because of our 200,000-square-mile footprint, but we manage our assets with reliability and affordability as top priorities. And when we join together with our neighboring utilities and transmission providers to pool our resources, we can add even more efficiency and further reduce costs. Participation in an RTO brings benefits in three main areas:

1. **RELIABILITY**
   Operating the grid from a regional perspective optimizes resources, reduces congestion and increases reliability.

2. **MARKETS**
   Real-time and day-ahead markets make the sale and purchase of power more economical and efficient.

3. **TRANSMISSION**
   Collaborative transmission planning across the region better enables integration of renewables, creates further efficiencies and helps with cost recovery for new facilities.

What progress has Tri-State made so far toward this regional collaboration?

In early 2021, Tri-State joined two organized markets – the Southwest Power Pool's Western Energy Imbalance Service (SPP WEIS) and the California Independent System Operator's Western Energy Imbalance Market (CAISO WEIM). This is an initial step in the direction of full participation in a western RTO, and energy imbalance markets give us the benefit of more efficient use of the transmission system and dispatch of the lowest-cost generation resources.

We've been working with other western utilities to evaluate expansion of SPP's RTO into the West. In July 2021, SPP's board approved policy-level terms and conditions for this expansion, keeping this process moving in a positive direction.

How does Tri-State plan for the resources needed in the future?

Resource planning is one of the most important things utilities do. It requires modeling everything we know today, like what generation and transmission resources we have, where there are constraints and what technology we have to manage it all. Then you have factors like future fuel prices, load forecasts and environmental regulations that can all add uncertainty. In the end we're looking to optimize the system based on the best information available.

In 2021, we continued the collaborative process of resource planning, modeling scenarios brought forward by a variety of stakeholders as part of our 2020 Electric Resource Plan (ERP) with the Colorado Public Utilities Commission (CPUC). We worked with numerous parties including our members, state officials, environmental advocates, developers and labor representatives to identify an affordable, reliable and responsible path forward, and reached a landmark settlement on the first phase of the ERP in early 2022.

How is Tri-State positioned to increase renewable generation as part of the resource mix?

Tri-State's service territory sits on an incredible natural resource mix. In addition to the access to dispatchable resources, like coal, oil, natural gas and hydro, we have ideal locations for solar and wind. We get a strong response to our RFPs for development of renewable generation projects and had two new wind projects come online in 2021, with six additional solar projects in development. These projects are located in our member systems' service territories, where their local communities benefit from the property and use taxes, and the member system serves electricity to the renewable facility.

All these activities are building momentum for a more efficient and responsible future where Tri-State and our members continue to prosper.

Our members

COLORADO

EM Empire Electric Association, Inc., Cortez
GC Gunnison County Electric Association, Inc., Gunnison
HL Highline Electric Association, Holyoke
KC K.C. Electric Association, Inc., Hugo
LP La Plata Electric Association, Inc., Durango
MC Morgan County Rural Electric Association, Fort Morgan
MP Mountain Parks Electric, Inc., Granby
MV Mountain View Electric Association, Inc., Limon
PV Poudre Valley Rural Electric Association, Inc., Fort Collins
SI San Isabel Electric Association, Inc., Pueblo West
SV San Luis Valley Rural Electric Cooperative, Inc., Monte Vista
SM San Miguel Power Association, Inc., Nucla
SC Sangre de Cristo Electric Association, Inc., Buena Vista
SE Southeast Colorado Power Association, La Junta
UN United Power, Inc., Brighton
WR White River Electric Association, Inc., Meeker
YW Y-W Electric Association, Inc., Akron

NEBRASKA

CR Chimney Rock Public Power District, Bayard
MW Midwest Electric Cooperative Corporation, Grant
NW Northwest Rural Public Power District, Hay Springs
PH Panhandle Rural Electric Membership Association, Alliance
RS Roosevelt Public Power District, Scottsbluff
WB Wheat Belt Public Power District, Sidney

NEW MEXICO

CN Central New Mexico Electric Cooperative, Inc., Mountainair
CO Columbus Electric Cooperative, Inc., Deming
CD Continental Divide Electric Cooperative, Inc., Grants
JM Jemez Mountains Electric Cooperative, Inc., Española
MO Mora-San Miguel Electric Cooperative, Inc., Mora
NR Northern Rio Arriba Electric Cooperative, Inc., Chama
OC Otero County Electric Cooperative, Inc., Cloudcroft
SR Sierra Electric Cooperative, Inc., Elephant Butte
SO Socorro Electric Cooperative, Inc., Socorro
SW Southwestern Electric Cooperative, Inc., Clayton
SP Springer Electric Cooperative, Inc., Springer

WYOMING

BH Big Horn Rural Electric Company, Basin
CB Carbon Power & Light, Inc., Saratoga
GL Garland Light & Power Company, Powell
HP High Plains Power, Inc., Riverton
HW High West Energy, Inc., Pine Bluffs
NB Niobrara Electric Association, Inc., Lusk
WL Wheatland Rural Electric Association, Wheatland
WY Wyrulec Company, Torrington

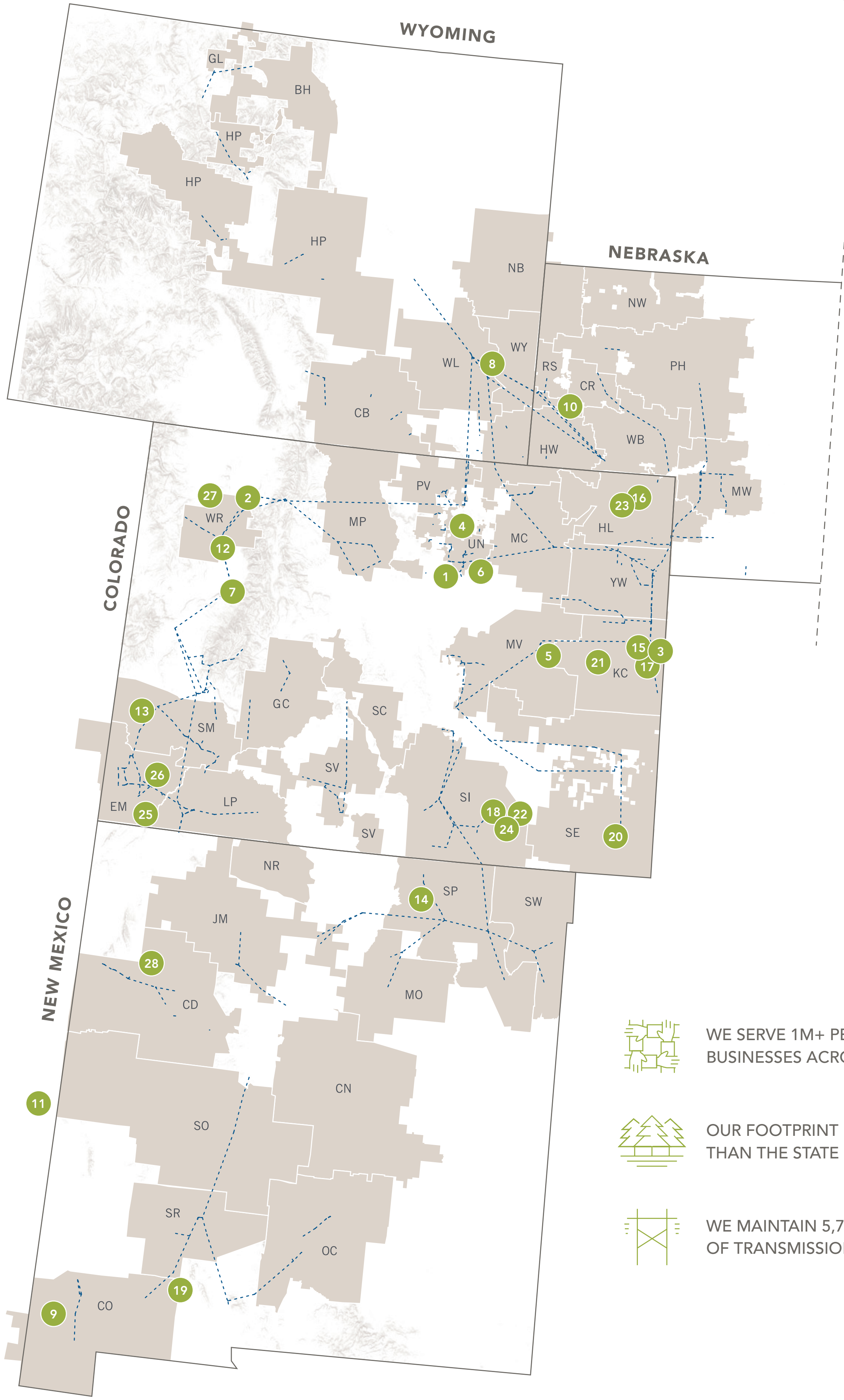
NON-UTILITY MEMBERS

Ellgen Ranch Company
MIECO, Inc.
Olson's Greenhouses of Colorado, LLC

Our resources

1. Headquarters and Operations Center – Westminster, CO
2. Craig Station – Craig, CO
3. Burlington Station – Burlington, CO
4. J.M. Shafer Generating Station – Fort Lupton, CO
5. Limon Generating Station – Limon, CO
6. Frank R. Knutson Generating Station – Brighton, CO
7. Rifle Generating Station – Rifle, CO
8. Laramie River Station – Wheatland, WY
9. Pyramid Generating Station – Lordsburg, NM
10. David A. Hamil DC Tie – Stegall, NE
11. Springerville Generating Station – Springerville, AZ
12. Colowyo Mine – Meeker, CO
13. New Horizon Mine (in full reclamation) – Nucla, CO
14. Cimarron Solar – Colfax County, NM
15. Kit Carson Windpower – Kit Carson County, CO
16. Colorado Highlands Wind – Logan County, CO
17. Carousel Wind – Kit Carson County, CO
18. San Isabel Solar – Las Animas County, CO
19. Alta Luna Solar – Luna County, NM
20. Twin Buttes II Wind – Prowers County, CO
21. Crossing Trails Wind – Kit Carson & Cheyenne Counties, CO
22. Spanish Peaks Solar (2023) – Las Animas County, CO
23. Niyol Wind – Logan County, CO
24. Spanish Peaks II Solar (2023) – Las Animas County, CO
25. Coyote Gulch Solar (2024) – Montezuma County, CO
26. Dolores Canyon Solar (2023) – Dolores County, CO
27. Axial Basin Solar (2023) – Moffat County, CO
28. Escalante Solar (2023) – McKinley County, NM

Tri-State also receives power from several small hydropower projects and under long-term contracts with the Western Area Power Administration and Basin Electric Power Cooperative.



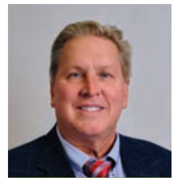
WE SERVE 1M+ PEOPLE AND BUSINESSES ACROSS 200,000MI²

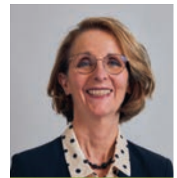
OUR FOOTPRINT IS 20% LARGER THAN THE STATE OF CALIFORNIA

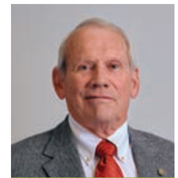
WE MAINTAIN 5,793 MILES OF TRANSMISSION LINE

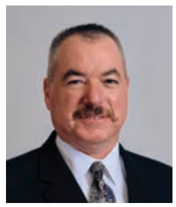
Our Board of Directors


CHAIRMAN
Tim Rabon
Otero County Electric


VICE CHAIRMAN
Don Keairns
San Isabel Electric


SECRETARY
Julie Kilty
Wyrulec Company


TREASURER
Stuart Morgan
Wheat Belt Public Power


Charles Abel II
Sangre de Cristo Electric


Leroy Anaya
Socorro Electric


Robert Baca
Mora-San Miguel Electric


Lucas Bear
Northwest Rural Public Power


Bruce Duran
Jemez Mountains Electric

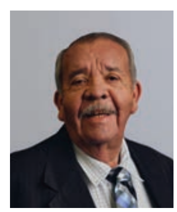

Jerry Fetterman
Empire Electric

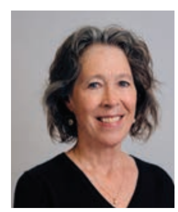

Jack Finnerty
Wheatland Rural Electric


Joel Gilbert
Southwestern Electric

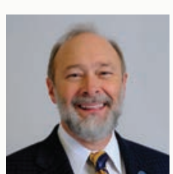

Stan Propp
Chimney Rock Public Power

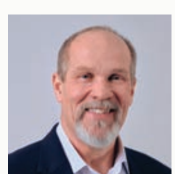

Steve Rendon
Northern Rio Arriba Electric

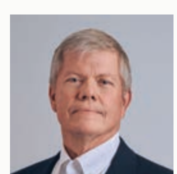

Claudio Romero
Continental Divide Electric

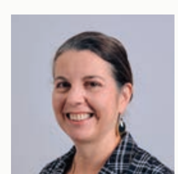

Peggy Ruble
Garland Light & Power

Our Executive Team


DUANE HIGHLEY
Chief Executive Officer


JOEL BLADOW
Senior Vice President Transmission

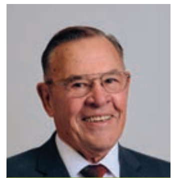

PAT BRIDGES
Senior Vice President and Chief Financial Officer

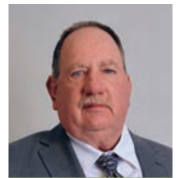

ELDA DE LA PEÑA
Senior Vice President People and Culture/ Chief Human Resources Officer


ASST. SECRETARY
Matt Brown
High Plains Power


ASST. SECRETARY
Scott Wolfe
San Luis Valley Rural Electric


EXEC. COMMITTEE
Wayne Connell
Central New Mexico Electric


EXEC. COMMITTEE
Thaine Michie
Poudre Valley Rural Electric


EXEC. COMMITTEE
Shawn Turner
Midwest Electric Cooperative


Robert Bledsoe
K.C. Electric


Lawrence Brase
Southeast Colorado Power


Leo Brekel
Highline Electric


Willie Bridges
Big Horn Rural Electric


Jerry Burnett
High West Energy


Kevin Cooney
San Miguel Power

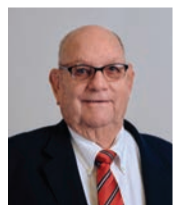

Mark Daily
Gunnison County Electric


Rick Gordon
Mountain View Electric


Randy Graff
Morgan County Rural Electric


Ron Hilkey
White River Electric


Ralph Hilyard
Roosevelt Public Power


Hal Keeler
Columbus Electric


Kohler McInnis
La Plata Electric


Brian McCormick
United Power


Roger Schenk
Y-W Electric


Gary Shaw
Springer Electric

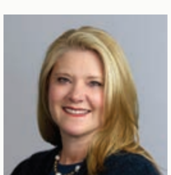

Darryl Sullivan
Sierra Electric


Clay Thompson
Carbon Power & Light

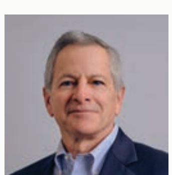

Carl Trick II
Mountain Parks Electric


William Wilson
Niobrara Electric


Phil Zochol
Panhandle Rural Electric

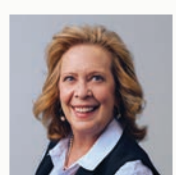

JENNIFER GOSS
Senior Vice President Member Relations and Chief Technology Officer


BARRY INGOLD
Senior Vice President Generation


BRAD NEBERGALL
Senior Vice President Energy Management


KEN REIF
Senior Vice President General Counsel


REG RUDOLPH
Senior Vice President Chief Energy Innovations Officer


BARBARA WALZ
Senior Vice President Policy and Compliance Chief Compliance Officer

DRIVING
CHANGE

Report of Ernst & Young LLP, Independent Registered Public Accounting Firm

To the Members and the Board of Directors of Tri-State Generation and Transmission Association, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of Tri-State Generation and Transmission Association, Inc. (the "Association") as of December 31, 2021 and 2020, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Association at December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Association's management. Our responsibility is to express an opinion on the Association's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Association in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Association is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Association's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

	Asset Retirement Obligations – Coal Mines
Description of the Matter	As discussed in Note 2 and 4 to the consolidated financial statements, the Association's obligations for the final reclamation costs and post-reclamation monitoring of the Association's coal mines are recognized at estimated fair value at the time the obligations are incurred and capitalized as part of the related long-lived asset. As changes in estimates occur, such as mine plans, estimated costs and timing

of reclamation activities, the Association makes revisions to the asset retirement obligation at the appropriate discount rate.

Auditing the Association's asset retirement obligations for coal mines required us to make subjective auditor judgements because the estimates underlying the determination of the obligations were based on significant assumptions utilized by management and their engineering staff. In particular, the fair value of the asset retirement obligation is determined by using a present value technique which is based on, among other things, estimates of disturbed areas, reclamation costs, timing of reclamation activities, and probability of outcomes.

How We Addressed the Matter in Our Audit

To audit the asset retirement obligation for coal mines, our procedures included evaluating the appropriateness of the Association's methodology and testing significant assumptions, as discussed above, and the underlying data used by the Association in its estimate. To assess the estimates of disturbed areas, reclamation costs, timing of reclamation activities, and probability of outcomes, we evaluated significant changes from the prior year estimate and verified consistency between the timing of activities to the projected mine life or reclamation plan. We also considered the appropriateness of the estimated reclamation costs for coal mines, compared anticipated labor and equipment costs to recent operating data and third-party evidence including common industry references, and recalculated management's estimate. We involved our specialists in our assessment of the Association's asset retirement obligations including reviewing the Association's methodology, interviewing members of the Association's engineering staff, evaluating the reasonableness of the cost estimates and assumptions, and assessing completeness of the estimate with respect to regulatory requirements.

Ernst + Young LLP

We have served as the Association's auditor since 1977.

Denver, Colorado
March 9, 2022

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

As of December 31,	2021	2020
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,606,732	$ 5,520,781
Construction work in progress	107,636	89,447
Total electric plant	5,714,368	5,610,228
Less allowances for depreciation and amortization	(2,367,197)	(2,279,950)
Net electric plant	3,347,171	3,330,278
Other plant	1,093,922	1,156,796
Less allowances for depreciation, amortization and depletion	(823,087)	(810,456)
Net other plant	270,835	346,340
Total property, plant and equipment	3,618,006	3,676,618
Other assets and investments		
Investments in other associations	163,097	162,975
Investments in and advances to coal mines	2,273	2,799
Restricted cash and investments	4,101	4,682
Other noncurrent assets	15,873	14,889
Total other assets and investments	185,344	185,345
Current assets		
Cash and cash equivalents	100,555	127,187
Restricted cash and investments	480	205
Deposits and advances	34,042	32,012
Accounts receivable—Members	95,630	96,637
Other accounts receivable	21,571	20,570
Electric plant held for sale	—	4,877
Coal inventory	59,701	55,762
Materials and supplies	87,234	82,119
Total current assets	399,213	419,369
Deferred charges		
Regulatory assets	665,693	710,268
Prepayment—NRECA Retirement Security Plan	16,117	21,490
Other	35,139	33,646
Total deferred charges	716,949	765,404
Total assets	**$ 4,919,512**	**$ 5,046,736**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 994,865	$ 978,519
Accumulated other comprehensive loss	(1,460)	(5,714)
Noncontrolling interest	119,100	114,851
Total equity	1,112,505	1,087,656
Long-term debt	3,101,870	3,200,181
Total capitalization	4,214,375	4,287,837
Current liabilities		
Member advances	17,217	16,592
Accounts payable	105,965	98,654
Short-term borrowings	49,997	—
Accrued expenses	32,882	40,736
Current asset retirement obligations	7,003	11,044
Accrued interest	25,716	27,520
Accrued property taxes	33,877	32,794
Current maturities of long-term debt	93,039	87,587
Total current liabilities	365,696	314,927
Deferred credits and other liabilities		
Regulatory liabilities	146,021	224,953
Deferred income tax liability	18,987	19,591
Asset retirement and environmental reclamation obligations	83,278	127,045
Other	78,319	54,600
Total deferred credits and other liabilities	326,605	426,189
Accumulated postretirement benefit and postemployment obligations	12,836	17,783
Total equity and liabilities	**$ 4,919,512**	**$ 5,046,736**

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

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

For the years ended December 31,	2021	2020	2019
Operating revenues			
Member electric sales	$ 1,161,291	$ 1,196,232	$ 1,238,672
Non-member electric sales	104,712	90,382	89,248
Rate stabilization	78,457	12,136	6,153
Other	56,341	53,545	51,399
	1,400,801	1,352,295	1,385,472
Operating expenses			
Purchased power	381,477	335,814	328,921
Fuel	236,089	234,844	280,325
Production	185,016	171,188	209,586
Transmission	182,327	170,933	163,757
General and administrative	57,243	69,796	49,607
Depreciation, amortization and depletion	190,237	185,243	157,734
Coal mining	5,323	11,691	10,027
Other	7,191	15,126	19,090
	1,244,903	1,194,635	1,219,047
Operating margins	**155,898**	**157,660**	**166,425**
Other income			
Interest	3,609	4,218	6,175
Capital credits from cooperatives	9,466	11,803	9,799
Other	4,152	1,831	18,427
	17,227	17,852	34,401
Interest expense			
Interest	143,328	151,423	160,169
Interest charged during construction	(3,786)	(6,088)	(8,699)
	139,542	145,335	151,470
Income tax expense (benefit)	295	(534)	(307)
Net margins including noncontrolling interest	33,288	30,711	49,663
Net margin attributable to noncontrolling interest	(6,942)	(5,590)	(4,354)
Net margins attributable to the Association	**$ 26,346**	**$ 25,121**	**$ 45,309**

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

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

For the years ended December 31,	2021	2020	2019
Net margins including noncontrolling interest	$ 33,288	$ 30,711	$ 49,663
Other comprehensive income (loss):			
Unrealized loss on securities available for sale	(108)	—	—
Unrecognized prior service credit on postretirement benefit obligation	5,698	—	—
Unrecognized actuarial gain (loss) on postretirement benefit obligation	784	625	(1,341)
Amortization of actuarial (gain) loss on postretirement benefit obligation included in net margin	78	—	(5)
Amortization of prior service cost credit on postretirement benefit obligation included in net margin	(2,139)	(79)	(79)
Unrecognized actuarial loss on executive benefit restoration obligation	(778)	(1,980)	(12)
Unrecognized prior service cost on executive benefit restoration obligation	(1,050)	(4,674)	(557)
Amortization of actuarial loss on executive benefit restoration obligation included in net margin	656	—	18
Amortization of prior service cost on executive benefit restoration obligation included in net margin	1,113	1,912	83
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	4,254	(4,196)	(1,893)
Comprehensive income including noncontrolling interest	37,542	26,515	47,770
Net comprehensive income attributable to noncontrolling interest	(6,942)	(5,590)	(4,354)
Comprehensive income attributable to the Association	**$ 30,600**	**$ 20,925**	**$ 43,416**

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

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

For the years ended December 31,	2021	2020	2019
Patronage capital equity at beginning of period	$ 978,519	$ 1,031,063	$ 1,015,754
Net margins attributable to the Association	26,346	25,121	45,309
Retirement of patronage capital	(10,000)	(77,665)	(30,000)
Patronage capital equity at end of period	**994,865**	**978,519**	**1,031,063**
Accumulated other comprehensive income (loss) at beginning of period	(5,714)	(1,518)	375
Unrealized loss on securities available for sale	(108)	—	—
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net margin	78	—	(5)
Reclassification adjustment for prior service credit on postretirement benefit obligation included in net margin	(2,139)	(79)	(79)
Reclassification adjustment for actuarial loss on executive benefit restoration obligation included in net margin	656	—	18
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	1,113	1,912	83
Unrecognized prior service credit on postretirement benefit obligation	5,698	—	—
Unrecognized actuarial gain (loss) on postretirement benefit obligation	784	625	(1,341)
Unrecognized actuarial loss on executive benefit restoration obligation	(778)	(1,980)	(12)
Unrecognized prior service cost on executive benefit restoration obligation	(1,050)	(4,674)	(557)
Accumulated other comprehensive loss at end of period	**(1,460)**	**(5,714)**	**(1,518)**
Noncontrolling interest at beginning of period	114,851	111,717	110,169
Net comprehensive income attributable to noncontrolling interest	6,942	5,590	4,354
Equity distribution to noncontrolling interest	(2,693)	(2,456)	(2,806)
Noncontrolling interest at end of period	**119,100**	**114,851**	**111,717**
Total equity at end of period	**$ 1,112,505**	**$ 1,087,656**	**$ 1,141,262**

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

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

For the years ended December 31,	2021	2020	2019
Operating activities			
Net margins including noncontrolling interest	$ 33,288	$ 30,711	$ 49,663
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	190,237	185,243	157,734
Amortization of intangible asset	—	—	3,662
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,372
Amortization of debt issuance costs	2,479	2,460	2,375
Impairment loss	—	274,645	37,067
Deferred impairment loss and other closure costs	—	(283,047)	(37,067)
Deferred membership withdrawal income	—	110,165	—
Deposits associated with generator interconnection requests	17,130	—	—
Rate stabilization	(78,457)	(12,136)	(6,153)
Capital credit allocations from cooperatives and income from coal mines over refund distributions	512	(1,268)	(1,276)
Changes in operating assets and liabilities:			
Accounts receivable	(3,618)	17,358	2,383
Coal inventory	(3,453)	(5,571)	5,692
Materials and supplies	(4,714)	(40)	154
Accounts payable and accrued expenses	13,114	(844)	1,136
Accrued interest	(1,804)	(2,196)	(2,354)
Accrued property taxes	1,082	3,665	547
Other	(1,261)	6,402	14,328
Net cash provided by operating activities	**169,907**	**330,919**	**233,263**
Investing activities			
Purchases of plant	(118,422)	(142,152)	(212,815)
Sale of electric plant	—	26,000	—
Changes in deferred charges	(13,054)	(4,885)	9,347
Proceeds from other investments	72	733	65
Net cash used in investing activities	**(131,404)**	**(120,304)**	**(203,403)**
Financing activities			
Changes in Member advances	183	(7,837)	(4,177)
Payments of long-term debt	(94,288)	(282,757)	(96,099)
Proceeds from issuance of long-term debt	—	425,000	34,910
Debt issuance costs	—	(637)	(13)
Change in short-term borrowings, net	49,997	(252,323)	48,178
Retirement of patronage capital	(18,067)	(70,881)	(23,303)
Equity distribution to noncontrolling interest	(2,693)	(2,456)	(2,806)
Other	(573)	(418)	(372)
Net cash used in financing activities	**(65,441)**	**(192,309)**	**(43,682)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**(26,938)**	**18,306**	**(13,822)**
Cash, cash equivalents and restricted cash and investments – beginning	**132,074**	**113,768**	**127,590**
Cash, cash equivalents and restricted cash and investments – ending	**$ 105,136**	**$ 132,074**	**$ 113,768**
Supplemental cash flow information:			
Cash paid for interest	$ 143,394	$ 152,570	$ 161,460
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 1,383	$ 440	$ (96)

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

Tri-State Generation and Transmission Association, Inc.

Notes to Consolidated Financial Statements

NOTE 1 – ORGANIZATION

Tri-State Generation and Transmission Association, Inc. (“Tri-State,” “we”, “our,” “us”, or “the Association”) is 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 on 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 15—Commitments and Contingencies—Legal.

We also sell a portion of our electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. In 2021, 2020 and 2019, total megawatt-hours sold were 17.6, 17.5 and 18.1 million, respectively, of which 89.1, 90.8 and 90.6 percent, respectively, were sold to Utility Members. Total revenue from electric sales was $1.3 billion for 2021, 2020 and 2019 of which 86.4, 92.1, and 92.8 percent in 2021, 2020 and 2019, respectively, was from Utility Member sales. Energy resources were provided by our generation and purchased power, of which 52.1, 58.2 and 61.5 percent in 2021, 2020 and 2019, respectively, were from our generation.

Power is provided to Utility Members at rates determined by our Board of Directors (“Board”), subject to FERC approval. Rates are designed to recover all costs and provide margins to increase Utility Members’ equity and to meet certain financial covenants, including a debt service ratio (“DSR”) requirement and equity to capitalization ratio (“ECR”) requirement.

We supply wholesale power to our Utility Members through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. Our generating facilities also include undivided ownership interests in jointly owned generating facilities. See Note 3—Property, Plant and Equipment. In support of our coal-fired generating facilities, we have direct ownership in coal mines.

We, including our subsidiaries, employ 1,191 people, of which 215 are subject to collective bargaining agreements. None of these agreements expire within one year.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF CONSOLIDATION: Our consolidated financial statements include the accounts of 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 14—Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities.

All significant intercompany balances and transactions have been eliminated in consolidation. The accompanying consolidated statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) as applied to regulated enterprises.

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 generation facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and operating expenses is included in our consolidated financial statements. See Note 3—Property, Plant and Equipment.

SEGMENT REPORTING: We are organized for the purpose of supplying wholesale power to our Utility Members and do so through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. In support of our coal-fired generating resources, we have direct ownership in coal mines. Our Board serves as our chief operating decision maker who manages and reviews our operating results and allocates resources as one operating segment. Therefore, we have one reportable segment for financial reporting purposes.

USE OF ESTIMATES: The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

IMPAIRMENT EVALUATION: Long-lived assets (property, plant and equipment, intangible assets, investments and preliminary surveys and investigation costs) that are held and used are evaluated for impairment whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. An impairment loss is recognized when estimated undiscounted cash flows expected to result from the use of the asset plus net proceeds expected from disposition of the asset (if any) are less than the carrying value of the asset. When an impairment loss is recognized, the carrying amount of the asset is reduced to its estimated fair value based on quoted market prices or other valuation techniques. There were no impairments of long-lived assets recognized in 2021. In 2020, we recognized an impairment loss of $274.6 million associated with the early retirement of the Escalante Generating Station, and in 2019, we recognized an impairment loss of $37.1 million associated with the early retirement of Nucla Generating Station. These impairment losses were deferred in accordance with the accounting requirements related to regulated operations at the discretion of our Board and subject to FERC approval, if applicable. See Note 2—Accounting for Rate Regulation.

VARIABLE INTEREST ENTITIES: We evaluate our arrangements and relationships with other entities, including our investments in other associations in accordance with the accounting standard related to consolidation of variable interest entities. This guidance requires us to identify variable interests (contractual, ownership or other financial interests) in other entities and whether any of those entities in which we have a variable interest, meets the criteria of a variable interest entity. An entity is considered to be a variable interest entity when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. In making this assessment, we consider the potential that our arrangements and relationships with other entities provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of an entity, the ability to directly or indirectly make decisions about the entity's activities and other factors. If an entity that we have a variable interest in meets the criteria of a variable interest entity, we must determine whether we are the primary beneficiary of that entity. The primary beneficiary is the entity that has the power to direct the activities of the variable interest entity that most significantly impact the variable interest entity's economic performance, and the obligation to absorb losses or the right to receive benefits from the variable interest entity that could be potentially significant to the variable interest entity. If we are determined to be the primary beneficiary of (has controlling financial interest in) a variable interest entity, then we would be required to consolidate that entity. In certain situations, it may be determined that power is shared among multiple unrelated parties such that no one party has the power to direct the activities of a variable interest entity that most significantly impact the variable interest entity's economic performance (decisions about those activities require the consent of each of the parties sharing power). In accordance with the accounting guidance prescribed by consolidation of variable interest entities, if the determination is made that power is shared among multiple unrelated parties, then no party is the primary beneficiary. See Note 14—Variable Interest Entities.

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, 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 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):

	December 31, 2021	December 31, 2020
Regulatory assets		
Deferred income tax expense (1)	$ 18,742	$ 19,641
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	79,133	81,424
Goodwill – J.M. Shafer (3)	43,447	46,296
Goodwill – Colowyo Coal (4)	35,128	36,161
Deferred debt prepayment transaction costs (5)	123,674	132,302
Deferred Holcomb expansion impairment loss (6)	84,145	88,819
Unrecovered plant (7)	281,424	305,625
Total regulatory assets	665,693	710,268
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	2,818	3,293
Deferred revenues (9)	—	63,717
Membership withdrawal (10)	143,203	157,943
Total regulatory liabilities	146,021	224,953
Net regulatory asset	$ 519,672	$ 485,315

(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 in rates.
(3) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP (“TCP”) in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Utility Members in rates.
(4) Represents goodwill related to our acquisition of Colowyo Coal Company LP (“Colowyo Coal”) in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $1.0 million annually through the 44-year period ending in 2056 and recovered from our Utility Members in rates.
(5) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of $8.6 million annually over the 21.4-year period ending in 2036 and recovered from our Utility Members in rates.
(6) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights for the expansion of the Holcomb Generating Station. The regulatory asset for the deferred impairment loss is being amortized to other operating expenses in the amount of $4.7 million annually over the 20-year period ending in 2039 and recovered from our Utility Members in rates.
(7) Represents deferral of the impairment losses related to the early retirement of the Nucla and Escalante Generating Stations. The deferred impairment loss for Nucla Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $9.1 million annually through December 2022 and recovered from our Utility Members through rates. The deferred impairment loss for Escalante Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $11.3 million annually over the 25-year period ending in December 2045, which was the depreciable life of Escalante Generating Station, and recovered from our Utility Members through rates. The annual amortization approximates the formal annual Escalante Generating Station depreciation for the remaining life of the asset.
(8) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A and refunded to Utility Members through reduced rates when recognized in future periods.
(9) Represented the deferral of the recognition of non-member electric sales revenues. As of December 31, 2021, these deferred non-member electric sales revenues were fully refunded to Utility Members through reduced rates. During 2021, $63.7 million was recognized in operating revenues as part of our rate stabilization measures.

(10) 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. During 2021, $14.7 million was recognized in operating revenues as part of our rate stabilization measures.

ELECTRIC PLANT AND DEPRECIATION: Electric plant is stated at cost. The cost of internally constructed assets includes payroll, overhead costs and interest charged during construction. Interest rates charged during construction were 4.4 percent for 2021, 4.6 percent for 2020 and 4.7 percent for 2019. The amount of interest capitalized during construction was $3.8, $6.1 and $8.7 million during 2021, 2020 and 2019, respectively. At the time that units of electric plant are retired, original cost and cost of removal, net of the salvage value, are charged to the allowance for depreciation. Replacements of electric plant that involve less than a designated unit value are charged to maintenance expense when incurred. Electric plant is depreciated based upon estimated depreciation rates and useful lives that are periodically re-evaluated. See Note 3—Property, Plant and Equipment.

COAL RESERVES AND DEPLETION: Coal reserves are recorded at cost. Depletion of coal reserves is computed using the units-of-production method utilizing only proven and probable reserves.

LEASES: We determine if an arrangement is a lease upon commencement of the contract. If an arrangement is determined to be a long-term lease (greater than 12 months), we recognize a right-of-use asset and lease liability based on the present value of the future minimum lease payments over the lease term at the commencement date. As most of our leases do not provide an implicit rate, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. Our lease terms may also include options to extend or terminate the lease when it is reasonably certain that we will exercise those options. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term. Right-of-use assets are included in other deferred charges, the current portion of lease liabilities is included in current liabilities and the long-term portion of lease liabilities is included in other deferred credits and other liabilities on our consolidated statements of financial position. See Note 11—Leases.

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 incurred.

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):

	December 31, 2021	December 31, 2020
Basin Electric Power Cooperative	$ 116,826	$ 118,295
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,076	11,933
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,149	15,221
CoBank, ACB	12,985	11,141
Other	6,061	6,385
Investments in other associations	$ 163,097	$ 162,975

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 2021, 2020 or 2019.

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 have been restricted by contract and 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 restricted by contract or other legal reasons and 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):

	December 31, 2021	December 31, 2020
Cash and cash equivalents	$ 100,555	$ 127,187
Restricted cash and investments - current	480	205
Restricted cash and investments - noncurrent	4,101	4,682
Cash, cash equivalents and restricted cash and investments	$ 105,136	$ 132,074

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 estimated fair value of the investments were $0.6 million and $0.5 million at December 31, 2021 and 2020, respectively.

INVENTORIES: Coal inventories at our owned generating facilities are stated at LIFO (last-in, first-out) cost and were $27.1 million and $24.2 million as of December 31, 2021 and 2020, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2021, we realized lower coal fuel expense of $0.2 million as a result of a LIFO inventory liquidation at our generating facilities.

OTHER DEFERRED CHARGES: We make expenditures for preliminary surveys and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects. If construction results, the preliminary survey and investigation expenditures will be reclassified to electric plant - construction work in progress. If the work is abandoned, the related preliminary survey and investigation expenditures will be charged to the appropriate operating expense account or the expense could be deferred as a regulatory asset to be recovered from our 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 11—Leases.

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

	December 31, 2021	December 31, 2020
Preliminary surveys and investigations	$ 12,366	$ 12,886
Advances to operating agents of jointly owned facilities	4,422	2,071
Operating lease right-of-use assets	7,529	7,985
Other	10,822	10,704
Total other deferred charges	$ 35,139	$ 33,646

DEBT ISSUANCE COSTS: We account for debt issuance costs as a direct deduction of the associated long-term debt carrying amount consistent with the accounting for debt discounts and premiums. Deferred debt issuance costs are amortized to interest expense using an effective interest method over the life of the respective debt.

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 a market risk premium. As changes in estimates occur, such as mine plans, estimated costs and timing of the performance of reclamation activities, we make revisions to the asset and obligation at the appropriate discount rate. Upon settlement of an asset retirement obligation, we will apply payment against the estimated liability and incur a gain or loss if the actual retirement costs differ from the estimated recorded liability.

Environmental reclamation costs are accrued based on management's best estimate at the end of each period of the costs expected to be incurred. Such cost estimates may include ongoing care, maintenance and monitoring costs. Changes in reclamation estimates are reflected in earnings in the period an estimate is revised. Estimates of future expenditures for environmental reclamation obligations are not discounted. See Note 4—Asset Retirement and Environmental Reclamation Obligations.

OTHER DEFERRED CREDITS AND OTHER LIABILITIES: In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. We will pay $28.7 million for these easements from 2022 through the individual easement terms ending between 2036 and 2040. The present value of the remaining easement payments was $19.3 million and $20.0 million as of December 31, 2021 and December 31, 2020, respectively, which is recorded as other deferred credits and other liabilities.

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.

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

	December 31, 2021	December 31, 2020
Transmission easements	$ 19,339	$ 19,983
Operating lease liabilities - noncurrent	1,622	1,590
Contract liabilities (unearned revenue) - noncurrent	3,523	3,702
Customer deposits	9,287	7,712
Financial liabilities - reclamation	13,122	12,081
OATT deposits	24,327	—
Other	7,099	9,532
Total other deferred credits and other liabilities	$ 78,319	$ 54,600

PATRONAGE CAPITAL: Our net margins are treated as advances of capital from our Members and are allocated to our Utility Members on the basis of their electricity purchases from us and to our Non-Utility Members as provided in their respective membership agreements. Margins not yet distributed to Members constitute patronage capital. Patronage capital is held for the account of our Members and is distributed through patronage capital retirements when our Board deems it appropriate to do so, subject to debt instrument restrictions.

ELECTRIC SALES REVENUE: Revenue from electric energy deliveries is recognized when delivered. See Note 10—Revenue.

OTHER OPERATING REVENUE: Other operating revenue consists primarily of wheeling, transmission, and coal sales revenue. Other operating revenue also includes revenue from our Non-Utility Members. Wheeling revenue is earned when we charge other energy companies for transmitting electricity over our transmission lines. 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). Coal sales revenue results from the sale of coal from the Colowyo Mine and other locations to third parties. The associated Colowyo Mine expenses are included in coal mining and depreciation, amortization, and depletion expense on our consolidated statements of operations.

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 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. See Note 9—Income Taxes.

INTERCHANGE POWER: We occasionally engage in interchanges, or non-cash swapping, of energy. Based on the assumption that all energy interchanged will eventually be received or delivered in-kind, interchanged energy is generally valued at the average cost of fuel to generate power. Additionally, portions of the energy interchanged are valued per contract with the utility involved in the interchange. When we are in a net energy advance position, the advanced energy balance is recorded as an asset. If we owe energy, the net energy balance owed to others is recorded as a liability. The net activity for the year is included in purchased power expense. The interchange liability balance of $2.9 and $2.2 million at December 31, 2021 and 2020, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was an expense of $0.6 million in 2021 and a credit of $0.1 million and $0.4 million in 2020 and 2019, respectively.

RECLASSIFICATIONS: Certain reclassifications have been made to the prior year financial statements to conform to the 2021 presentation.

NOTE 3 – PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consists of electric plant and other plant. Both of these are discussed below and are included on our consolidated statements of financial position.

ELECTRIC PLANT: At December 31, 2021, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

	Annual Depreciation Rate			Plant In Service	Accumulated Depreciation	Net Book Value
Generation plant	0.89 %	to	6.27 %	$ 3,049,233	$ (1,318,197)	$ 1,731,036
Transmission plant	1.11 %	to	2.09 %	1,879,148	(672,556)	1,206,592
General plant	1.46 %	to	9.53 %	406,693	(251,567)	155,126
Other	2.75 %	to	10.00 %	271,658	(124,877)	146,781
Electric plant in service (at cost)				$ 5,606,732	$ (2,367,197)	3,239,535
Construction work in progress						107,636
Electric plant						$ 3,347,171

At December 31, 2020, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

	Annual Depreciation Rate			Plant In Service	Accumulated Depreciation	Net Book Value
Generation plant	0.89 %	to	6.27 %	$ 2,957,150	$ (1,187,541)	$ 1,769,609
Transmission plant	1.11 %	to	2.09 %	1,820,994	(627,330)	1,193,664
General plant	1.46 %	to	9.53 %	490,850	(341,440)	149,410
Other	2.75 %	to	10.00 %	251,787	(123,639)	128,148
Electric plant in service (at cost)				$ 5,520,781	$ (2,279,950)	3,240,831
Construction work in progress						89,447
Electric plant						$ 3,330,278

At December 31, 2021, we had $46.3 million of commitments to complete construction projects, of which approximately $22.4, $18.2 and $5.7 million are expected to be incurred in 2022, 2023 and 2024, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2021 (these electric plant in service, accumulated depreciation and construction work in progress amounts are included in the electric plant table above) (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 %	$ 392,397	$ 254,985	$ 39
MBPP - Laramie River Station	28.50 %	523,678	336,371	3,326
Total		$ 916,075	$ 591,356	$ 3,365

OTHER PLANT: Other plant consists of mine assets (discussed below) and non-utility assets which consist of facilities not in service, land and irrigation equipment.

We own 100 percent of Elk Ridge Mining and Reclamation, LLC ("Elk Ridge"), organized for the purpose of acquiring coal reserves and supplying coal to us. Elk Ridge is the owner of Colowyo Mine, a surface coal mine near Craig, Colorado and New Horizon Mine, near Nucla, Colorado. New Horizon Mine is in reclamation and no longer produces coal. The expenses related to Colowyo coal used by us are included in fuel expense on our consolidated statements of operations.

Other plant assets are as follows (dollars in thousands):

	December 31, 2021	December 31, 2020
Colowyo Mine assets	$ 376,868	$ 415,739
New Horizon Mine assets	5,061	4,389
Accumulated depreciation and depletion	(133,951)	(98,731)
Net mine assets	247,978	321,397
Non-utility assets	711,993	736,668
Accumulated depreciation	(689,136)	(711,725)
Net non-utility assets	22,857	24,943
Net other plant	$ 270,835	$ 346,340

NOTE 4 – ASSET RETIREMENT AND ENVIRONMENTAL RECLAMATION OBLIGATIONS

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

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

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

	2021	2020
Obligations at beginning of period	$ 138,089	$ 78,914
Liabilities incurred	1,475	2,527
Liabilities settled	(4,934)	(3,689)
Accretion expense	2,409	2,506
Change in cash flow estimate	(46,758)	57,831
Total obligations at end of period	$ 90,281	$ 138,089
Less current obligations at end of period	(7,003)	(11,044)
Long-term obligations at end of period	$ 83,278	$ 127,045

During 2021, we recorded a reduction of the Colowyo Mine reclamation liability of $40.7 million. This reduction was primarily related to a change in the mine plan of South Taylor pit at the Colowyo Mine. After obtaining regulatory approval, the South Taylor pit life was extended through 2027 to mine the highwall, which resulted in a lower estimated obligation at the end of the mining period. The West pit is currently in final reclamation. We continue to evaluate the Colowyo Mine and New Horizon Mine post reclamation obligations and will make adjustments to these obligations as needed.

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 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

Contract Assets

A contract asset represents an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer when that right is conditioned on something other than the passage of time (for example, the entity's future performance). We have no contract assets as of December 31, 2021 and December 31, 2020.

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 10—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. We recognized $0.7 million of this unearned revenue in 2021 in other operating revenues on our consolidated statements of operations.

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

	December 31, 2021	December 31, 2020
Accounts receivable - Members	$ 95,630	$ 96,637
Other accounts receivable - trade:		
Non-member electric sales	5,684	5,231
Other	13,505	9,785
Total other accounts receivable - trade	19,189	15,016
Other accounts receivable - nontrade	2,382	5,554
Total other accounts receivable	$ 21,571	$ 20,570
Contract liabilities (unearned revenue)	$ 5,372	$ 6,025

NOTE 6 – LONG-TERM DEBT

We have $3.1 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture") except for one unsecured note in the aggregate amount of $12.0 million as of December 31, 2021. 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 DSR requirement on an annual basis and an ECR requirement of at least 18 percent at the end of each fiscal year. Other than long-term debt for the Springerville certificates that has a DSR requirement of at least 1.02 on an annual basis, all other long-term debt contains a DSR requirement of at least 1.10 on an annual basis.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC"), as lead arranger and administrative agent, in the amount of $650 million ("Revolving Credit Agreement") that expires on April 25, 2023. We had no outstanding borrowings under the Revolving Credit Agreement as of December 31, 2021. As of December 31, 2021, we had $600 million in availability (including $450 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

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

	December 31, 2021	December 31, 2020
Mortgage notes payable		
3.66% to 8.08% CFC, due through 2028	$ 106,182	$ 115,583
2.63% to 4.43% CoBank, ACB, due through 2042	204,163	220,704
First Mortgage Obligations, Series 2017A, Tranche 1, 3.34%, due through 2029	60,000	60,000
First Mortgage Obligations, Series 2017A, Tranche 2, 3.39%, due through 2029	60,000	60,000
First Mortgage Bonds, Series 2016A, 4.25% due 2046	250,000	250,000
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	244,714	250,000
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	250,000	250,000
First Mortgage Bonds, Series 2010A, 6.00% due 2040	500,000	500,000
First Mortgage Obligations, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000	180,000
First Mortgage Obligations, Series 2014B, Tranche 2, 4.30%, due through 2039	20,000	20,000
First Mortgage Obligations, Series 2014B, Tranche 3, 4.45%, due through 2045	550,000	550,000
First Mortgage Obligations, Series 2009C, Tranche 2, 6.31%, due through 2021	—	22,000
Variable rate CFC, as determined by CFC, due through 2026	324	386
Variable rate CFC, LIBOR-based term loan, due through 2049	152,220	152,220
Variable rate CoBank, ACB, LIBOR-based term loans, due through 2044	297,039	297,039
Pollution control revenue bonds		
Moffat County, CO, 2.00% term rate through October 2022, Series 2009, due 2036	46,800	46,800
Springerville certificates		
Series B, 7.14%, due through 2033	292,985	333,983
Total long-term debt	$ 3,214,427	$ 3,308,715
Less debt issuance costs	(23,110)	(25,590)
Less debt discounts	(9,398)	(9,659)
Plus debt premiums	12,990	14,302
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,194,909	$ 3,287,768
Less current maturities	(93,039)	(87,587)
Long-term debt	$ 3,101,870	$ 3,200,181

Annual maturities of total long-term debt adjusted for debt issuance costs, discounts and premiums at December 31, 2021 are as follows (dollars in thousands):

2022	$ 93,039
2023	93,083
2024 (1)	340,787
2025	89,168
2026	90,752
Thereafter	2,488,080
	$ 3,194,909

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(1) Includes $245 million bullet maturity for the First Mortgage Bonds, Series 2014 E-1.

NOTE 7 – SHORT-TERM BORROWINGS

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

Commercial paper consisted of the following as of and for the twelve months ended December 31 (dollars in thousands):

	2021	2020
Commercial paper outstanding, net of discounts	$ 49,997	$ —
Weighted average interest rate	0.20 %	— %

At December 31, 2021, $450 million of the commercial paper back-up sublimit remained available under the Revolving Credit Agreement. See Note 6—Long-Term Debt.

NOTE 8 – 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 market, or in the most advantageous market when no principal market exists. The fair value measurements accounting guidance emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability (market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress). In considering market participant assumptions in fair value measurements, a three-tier fair value hierarchy for measuring fair value was established which prioritizes the inputs used in measuring fair value as follows:

Level 1 inputs 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 and 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.

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 investments in the Executive Benefit Restoration Plan trust are as follows (dollars in thousands):

	December 31, 2021		December 31, 2020	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 8,850	$ 8,640	$ 6,955	$ 6,955

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 amortized cost and fair values of our marketable securities are as follows (dollars in thousands):

	December 31, 2021		December 31, 2020	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 597	$ 598	$ 491	$ 478

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $95.3 million and $95.0 million as of December 31, 2021 and 2020, respectively.

Debt

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

	December 31, 2021		December 31, 2020	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,214,427	$ 3,759,991	$ 3,308,715	$ 3,908,497

NOTE 9 – INCOME TAXES

We had no current income tax expense or benefit in 2021. We had a current income tax benefit of $0.5 million and $0.3 million in 2020 and 2019, respectively, due to our election to receive an alternative minimum tax credit refund in lieu of recognizing bonus depreciation.

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 received or settled through future rate revenues.

Components of our net deferred tax liability are as follows (dollars in thousands):

	December 31, 2021	December 31, 2020
Deferred tax assets		
Safe harbor lease receivables	$ 8,135	$ 11,604
Net operating loss carryforwards	144,602	116,430
Deferred revenues and membership withdrawal	38,784	57,704
Operating lease liabilities	114,237	123,459
Other	30,578	39,277
	336,336	348,474
Less valuation allowance	—	—
	336,336	348,474
Deferred tax liabilities		
Basis differences- property, plant and equipment	159,696	167,243
Capital credits from other associations	31,622	30,809
Deferred debt prepayment transaction costs	29,434	31,488
Operating lease right-of-use assets	130,111	133,850
Other	4,460	4,675
	355,323	368,065
Net deferred tax liability	$ (18,987)	$ (19,591)

Net deferred tax liabilities decreased by $0.6 million in 2021 and reflected as a decrease in the regulatory asset established for deferred income tax expense. The accounting for regulatory assets is discussed further in Note 2—Accounting for Rate Regulation. The regulatory asset balance associated with deferred income tax expense under the liability method is $18.7 million and $19.6 million at December 31, 2021 and 2020, respectively.

The reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	2021	2020	2019
Federal income tax expense at statutory rate	21.00 %	21.00 %	21.00 %
State income tax expense, net of federal benefit	2.80	2.80	2.80
Patronage exclusion	(23.80)	(23.80)	(23.80)
Asset retirement obligations	42.18	(56.69)	(11.33)
Deferred revenues and membership withdrawal	72.15	(117.60)	3.23
Operating liabilities, net of right-of-use assets	4.50	21.02	11.29
Valuation Allowance	—	(121.38)	67.24
Net operating loss	(106.41)	1.46	(35.82)
Other book tax differences	(11.29)	69.88	33.39
Impairment	—	81.88	—
Regulatory treatment of deferred taxes	(1.51)	119.29	(68.68)
Effective tax rate	(0.38)%	(2.14)%	(0.68)%

We had an estimated tax loss of $115.7 million for 2021. At December 31, 2021, we have an estimated consolidated federal net operating loss carryforward of $609.6 million of which pre-2018 tax years in the amount of $444.5 million are subject to expiration periods between 2031 and 2037 and $165.1 million have no expiration. We have $359.6 million of state net operating loss carryforwards, of which $323.2 million is subject to expiration periods between 2030 and 2039 and $36.4 million have no expiration. We did not establish a valuation allowance because it is more likely than not that the benefit from the federal and state net operating losses will be realized in the future.

We file a U.S. federal consolidated income tax return and income tax returns in state jurisdictions where required. The statute of limitations remains open for federal and state returns for the years 2018 forward. We do not have any liabilities recorded for uncertain tax positions.

NOTE 10 - 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 forty-two 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 – Members on our consolidated statements of financial position.

Revenue from one Utility Member, United Power, Inc. ("United Power"), was $215.2 million, or 18.5 percent, of our Utility Member revenue and 15.4 percent of our total operating revenues in 2021. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues in 2021.

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):

	2021	2020	2019
Non-member electric sales:			
Long-term contracts	$ 44,383	$ 46,172	$ 47,224
Short-term contracts	60,329	44,210	42,024
Rate stabilization	78,457	12,136	6,153
Coal Sales	4,951	7,326	6,662
Other	51,390	46,219	44,737
Total non-member electric sales and other operating revenue	$ 239,510	$ 156,063	$ 146,800

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 $78.5 million of deferred non-member electric sales revenue and deferred membership withdrawal income for the year ended December 31, 2021, and $12.1 million and $6.2 million of deferred non-member electric sales revenue for the years ended December 31, 2020 and December 31, 2019, respectively, as directed by our Board. See Note 2—Accounting for Rate Regulation.

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 received 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 11 – LEASES

Leasing Arrangements as Lessee

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 $3.5 million in 2021 and $2.8 million in 2020. Rent expense is included in operating expenses on our consolidated statements of operations. As of December 31, 2021, there were no arrangements accounted for as finance leases.

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

	December 31, 2021	December 31, 2020
Operating leases		
Operating lease right-of-use assets	$ 9,081	$ 9,223
Less: Accumulated amortization	(1,552)	(1,238)
Net operating lease right-of-use assets	$ 7,529	$ 7,985
Operating lease liabilities – current	$ (491)	$ (526)
Operating lease liabilities – noncurrent	(1,622)	(1,590)
Total operating lease liabilities	$ (2,113)	$ (2,116)
Operating leases		
Weighted average remaining lease term (years)	5.4	7.6
Weighted average discount rate	3.79 %	3.84 %

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

Year 1	$ 447
Year 2	390
Year 3	328
Year 4	919
Year 5	92
Thereafter	641
Total lease payments	$ 2,817
Less imputed interest	(704)
Total	$ 2,113

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $7.3 million in 2021 and $6.6 million in 2020 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 14—Variable Interest Entities. However, as the noncontrolling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded. See Note 9—Income Taxes.

NOTE 12 – RELATED PARTIES

TRAPPER MINING, INC.: We were a member of Trapper Mining. Organized as a cooperative, Trapper Mining supplied 0.0, 25.7 and 24.7 percent in 2021, 2020 and 2019, respectively, of our coal for the Yampa Project. Our former 26.57 percent share of coal purchases from Trapper Mining was $0.0, $20.2 and $18.6 million in 2021, 2020 and 2019, respectively. In December 2020, upon termination of our coal supply agreement with Trapper Mining, we withdrew from membership in Trapper Mining. Our investment in Trapper Mining was recorded using the equity method. Our membership interest in Trapper Mining was $0.0 at December 31, 2021 and 2020, respectively.

NOTE 13 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,191 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan ("RS Plan") except for the 190 employees of Colowyo Coal and any non-bargaining employees hired May 1, 2021 or later and bargaining employees hired July 1, 2021 or later. The RS Plan is a defined benefit pension plan qualified under Section 401(a) and tax-exempt under Section 501(a) of the Internal Revenue Code. It is considered a multiemployer plan under the accounting standards for compensation - retirement benefits. The plan sponsor's Employer Identification Number is 53-116145 and the Plan Number is 333.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits to any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

Our contributions to the RS Plan in each of the years 2021, 2020 and 2019 represented less than 5 percent of the total contributions made each year to the plan by all participating employers. We made contributions to the RS Plan of $26.7, $27.5 and $25.8 million in 2021, 2020 and 2019, respectively.

In December 2012, the National Rural Electric Cooperative Association ("NRECA") approved an option to allow participating cooperatives in the RS Plan to make a contribution prepayment and reduce future required contributions. The prepayment amount is a cooperative's share, as of January 1, 2013, of future contributions required to fund the RS Plan's unfunded value of benefits earned to date using RS Plan actuarial valuation assumptions. The prepayment amount is equal to approximately 2.5 times a cooperative's annual RS Plan required contribution as of January 1, 2013. After making the prepayment, the annual contribution was reduced by approximately 25 percent, retroactive to January 1, 2013. The reduced annual contribution is expected to continue for approximately 15 years. However, changes in interest rates, asset returns and other plan experience different from expected, plan assumption changes and other factors may have an impact on future contributions and the 15-year period.

In May 2013, we elected to make a contribution prepayment of $71.2 million to the RS Plan. This contribution prepayment was determined to be a long-term prepayment and therefore recorded in deferred charges and amortized beginning January 1, 2013 over the 13-year period calculated by subtracting the average age of our workforce from our normal retirement age under the RS Plan.

Our contributions to the RS Plan include contributions for substantially all of the 215 bargaining unit employees that are made in accordance with collective bargaining agreements. We ceased to add new bargaining employees hired July 1, 2021 or later and non-bargaining employees hired May 1, 2021 or later to the RS Plan.

For the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act ("Act") of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded at both January 1, 2021 and January 1, 2020, based on the Act funding target and the Act actuarial value of assets on those dates.

Because the provisions of the Act do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as part of the actuarial valuation of the plan and may change as a result of plan experience.

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 postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	2021	2020
Executive benefit restoration obligation at beginning of period	$ 7,379	$ 674
Service cost	440	332
Interest cost	205	434
Plan amendments - prior service cost	1,050	4,674
Benefit payments	—	(715)
Actuarial loss	778	1,980
Executive benefit restoration obligation at end of period	$ 9,852	$ 7,379
Fair value of plan assets at beginning of year	$ 6,955	$ —
Employer contributions	1,762	6,955
Actual return on plan assets	(77)	—
Fair value of plan assets at end of year	$ 8,640	$ 6,955
Net liability recognized	$ 1,212	$ 424

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):

	2021	2020
Accumulated other comprehensive loss at beginning of period	$ (4,873)	$ (130)
Plan amendments - prior service cost	(1,050)	(4,674)
Amortization of prior service cost into other income	1,113	1,911
Amortization of actuarial loss	515	—
Curtailment and settlement	141	—
Unrecognized actuarial loss	(778)	(1,980)
Accumulated other comprehensive loss at end of period	$ (4,932)	$ (4,873)

DEFINED CONTRIBUTION PLAN: We offer one 401(k) plan to all of our employees. We contribute 1 percent of employee base salary for all non-bargaining employees hired prior to May 1, 2021. All non-bargaining employees hired May 1, 2021 or later and all bargaining employees hired July 1, 2021 or later are eligible for a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match up to IRS allowed annual maximum. We offer one 401(k) plan to all employees of Colowyo Coal at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions for employees hired prior to May 1, 2021 and provide a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match for employees hired May 1, 2021 or later. All employees are eligible to contribute up to 75 percent of their salary on a pre-tax basis. Under all plans, total 401(k) contributions are not to exceed annual IRS limitations which are set annually. Employees who have attained age 50 in a calendar year are eligible for the catch-up contribution with maximum contribution limits determined annually by the IRS. We made contributions to the plan of $3.3 million, $3.5 million, and $3.5 million in 2021, 2020, and 2019, respectively.

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS: We sponsor three medical plans for all non-bargaining unit employees under the age of 65. Two of the plans provide postretirement medical benefits to full-time non-bargaining unit employees and retirees who receive benefits under those plans, who have attained age 55, and who elect to participate. All three of these non-bargaining unit medical plans offer postemployment medical benefits to employees on long-term disability. The plans were unfunded at December 31, 2021, 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 postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

	2021	2020
Postretirement medical benefit obligation at beginning of period	$ 9,985	$ 10,195
Service cost	—	601
Interest cost	36	259
Benefit payments (net of contributions by participants)	(730)	(456)
Actuarial gain	(784)	(614)
Plan amendments	(5,698)	—
Postretirement medical benefit obligation at end of period	$ 2,809	$ 9,985
Postemployment medical benefit obligation at end of period	419	419
Total postretirement and postemployment medical obligations at end of period	$ 3,228	$ 10,404

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

In accordance with the accounting standard related to postretirement benefits other than pensions, actuarial gains and losses are not recognized in income but are instead recorded in accumulated other comprehensive 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 amount 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 obligation are included in accumulated other comprehensive income as follows (dollars in thousands):

	2021	2020
Amounts included in accumulated other comprehensive income at beginning of period	$ (841)	$ (1,387)
Amortization of prior service credit into other income	(2,139)	(79)
Amortization of actuarial loss into other income	78	—
Actuarial gain	784	625
Plan amendments	5,698	—
Amounts included in accumulated other comprehensive income at end of period	$ 3,580	$ (841)

The assumptions used in the 2021 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	1.12 %
Initial health care cost trend (2018)	7.50 %
Ultimate health care cost trend	4.50 %
Year that the rate reached the ultimate health care cost trend rate	2027
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	3.48

The following are the expected future benefits to be paid (net of contributions by participants) related to the postretirement medical benefit obligation during the next ten years (dollars in thousands):

2022	$ 647,045
2023	522,088
2024	437,346
2025	352,112
2026	277,960
2025 through 2029	566,923
	$ 2,803,474

NOTE 14 – VARIABLE INTEREST ENTITIES

The following is a description of our financial interests in variable interest entities that we consider significant. This includes an entity for which we are determined to be the primary beneficiary and therefore consolidate and also entities for which we are not the primary beneficiary and therefore do not consolidate.

Consolidated Variable Interest Entity

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

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

	December 31, 2021	December 31, 2020
Net electric plant	$ 740,135	$ 758,273
Noncontrolling interest	119,101	114,852
Long-term debt	300,220	342,355
Accrued interest	8,721	9,942

Our consolidated statements of operations include the following Springerville Partnership expenses for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Depreciation, amortization and depletion	$ 18,138	$ 18,138	$ 18,138
Interest	20,038	22,798	25,320

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

Unconsolidated Variable Interest Entities

Western Fuels Association: WFA is a non-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which included us. In December 2020, we withdrew from membership in WFA. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in WFW. The pricing structure of the coal supply agreements with WFA were designed to recover the mine operating costs of the mine supplying the coal and therefore the coal sales agreements provide the financial support for the mine operations. There is not sufficient equity at risk for WFA to finance its activities without additional financial support. Therefore, WFA is considered a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact WFA's economic performance (acquiring and supplying fuel resources) is held by the members who are represented on the WFA board of directors whose actions require joint approval. Therefore, since there is shared power over the significant activities of WFA, we were not the primary beneficiary of WFA and the entity is not consolidated. In December 2020, we ceased having any representation on the WFA board of directors. Our investment in WFA (including MBPP), accounted for using the cost method, was $2.1 million at December 31, 2021 and 2020 and is included in investments in other associations.

Western Fuels – Wyoming: WFW, the owner and operator of the Dry Fork Mine in Gillette, Wyoming, is organized for the purpose of acquiring and supplying coal, through long-term coal supply agreements, to be used in the production of electric energy at the Laramie River Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by Basin). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 28.50 percent undivided interest) own the remaining 25 percent of class BB shares of WFW. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Dry Fork Mine and therefore the coal supply agreements provide the financial support for the operation of the Dry Fork Mine. There is not sufficient equity at risk at WFW for it to finance its activities without additional financial support. Therefore, WFW is considered a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact WFW's economic performance (which includes operations, maintenance and reclamation activities) is shared with the equity interest holders since each member has representation on the WFW board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of WFW and the entity is not consolidated. In December 2020, we ceased having any representation on the WFW board of directors. Our investment in WFW, accounted for using the cost method, was $0.1 million at December 31, 2021 and 2020 and is included in investments in other associations.

Trapper Mining, Inc.: Trapper Mining is a cooperative organized for the purpose of mining, selling and delivering coal from the Trapper Mine to the Craig Station Units 1 and 2 through long-term coal supply agreements. Trapper Mining is jointly owned by some of the participants of the Yampa Project. We had a 26.57 percent cooperative member interest in Trapper Mining. In December 2020, upon termination our coal supply agreement with Trapper Mining, we withdrew from membership in Trapper Mining. The pricing structure of the coal supply agreements were designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provided the financial support for the operation of the Trapper Mine. There was not sufficient equity at risk for Trapper Mining to finance its activities without additional financial support. Therefore, we considered Trapper Mining a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact Trapper Mining's economic performance (which includes operations, maintenance and reclamation activities) was shared with the cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we were not the primary beneficiary of Trapper Mining and the entity was not consolidated. We recorded our investment in Trapper Mining using the equity method. In December 2020, we ceased having any representation on the Trapper Mining board of directors. Our membership interest in Trapper Mining was $15.9 million at December 31, 2019, and is included in investments in and advances to coal mines. We had no membership interest in Trapper Mining as of December 31, 2021 or December 31, 2020.

NOTE 15 – COMMITMENTS AND CONTINGENCIES

SALES: We have a resource-contingent power sales contract with Salt River Project Agricultural Improvement and Power District of 100 megawatts through August 31, 2036.

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under contracts that expire between 2024 and 2041. These contracts require us to purchase a minimum quantity of coal at prices subject to escalation reflecting cost increases incurred by the suppliers due to market conditions. The coal purchase projection includes estimated future prices. As of December 31, 2021, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2022	$ 34,511
2023	19,238
2024	16,520
2025	4,962
2026	5,102
Thereafter	86,482
	$ 166,815

Our coal purchases were $97.9 million in 2021, $101.2 million in 2020, and $125.4 million in 2019.

ELECTRIC POWER PURCHASE AGREEMENTS: Our largest long-term electric power purchase contracts are with Basin and Western Area Power Administration ("WAPA"). We purchase from Basin power pursuant to two contracts: one relating to all the power which we require to serve our Utility Members' load in the Eastern Interconnection and one relating to fixed scheduled quantities of electric power in the Western Interconnection. Both contracts with Basin continue through December 31, 2050 and are subject to automatic extension thereafter.

We purchase renewable power under long-term contracts, including hydroelectric power from WAPA and from specified renewable generating facilities, including wind, solar and small hydro. We purchase from WAPA power pursuant to two contracts relating to WAPA's Loveland Area Projects (one which terminates September 30, 2024 and one which commences delivery on October 1, 2024 and terminates September 30, 2054) and three contracts relating to WAPA's Salt Lake City Area Integrated Projects (two which terminate September 30, 2024 and one which commences delivery on October 1, 2024 and terminates September 30, 2057).

As of December 31, 2021, we have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,521 MWs, including 674 MWs of wind-based power purchase agreements and 820 MWs of solar-based power purchase agreements that expire between 2030 and 2042.

Costs under the above electric power purchase agreements for the years ended December 31 were as follows (dollars in thousands):

	2021	2020	2019
Basin	$ 146,532	$ 152,461	$ 145,008
WAPA	70,107	72,491	72,504
Renewables, other than WAPA	71,565	69,255	63,677

ENVIRONMENTAL: As with most electric utilities, we are subject to extensive federal, state and local environmental requirements that regulate, among other things, air emissions, water discharges and the use and management of hazardous and solid wastes. Compliance with these requirements requires significant expenditures for the installation, maintenance and operation of pollution control equipment, monitoring systems and other equipment or facilities.

Our operations are subject to environmental laws and regulations that are complex, change frequently and have historically become more stringent and numerous over time. Federal, state, and local standards and procedures that regulate environmental impact of our operations are subject to change. Consequently, there is no assurance that environmental regulations applicable to our facilities will not become materially more stringent, or that we will always be able to obtain all required operating permits. More stringent standards may require us to modify the design or operation of existing facilities or purchase emission allowances. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of our facilities that are not in compliance, including the shutting down of additional generating facilities or the shutting down of individual coal-fired generating facilities earlier than scheduled. The cost impact of the implementation of regulation on existing legislation and future legislation or regulation will depend upon the specific requirements thereof and cannot be determined at this time, but it could have a significant effect on our financial condition, results of operations and cash flow.

From time to time, we are alleged to be in violation or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. Additionally, we may need to deal with notices of violation, enforcement proceedings or challenges to construction or operating permits. In addition, we may be involved in legal proceedings arising in the ordinary course of business. However, we believe our facilities are currently in compliance with such regulatory and operating permit requirements.

LEGAL:

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 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 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. 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 and wholesale electric service contracts. The tariff rates were referred to an administrative law judges to encourage settlement of material issues and to hold hearings if settlements were not reached. On April 30, 2021, we filed a proposed settlement agreement with FERC related to our Utility Member stated rate for approval, as further discussed below. On October 22, 2021, we filed a proposed settlement agreement with FERC related to our transmission service rates for approval, as further discussed below. FERC's March 20, 2020 order regarding our Jurisdictional PDO denied our requested declaration regarding the preemption of the United Power and LPEA proceeding at the COPUC stating the proceeding is not currently preempted.

On July 17, 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 March 20, 2020 order related to our Utility Member rates, USCA Case#20-1258, and such matter is being held in abeyance pending resolution of the Jurisdictional PDO appeal discussed below.

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 by finding exclusive jurisdiction over our contract termination payments 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 D.C. Circuit Court of Appeals related to FERC's August 28 Order, USCA Case#20-1256. Petitions for review related to both the Jurisdictional PDO and tariff filings have been filed with the D.C. Circuit Court of Appeals by other parties.

FERC, United Power, and the other parties reached agreement on the procedures and schedule for the Jurisdictional PDO filed with the D.C. Circuit Court of Appeals. On June 7, 2021, United Power filed its brief with the D.C. Circuit Court of Appeals regarding the Jurisdictional PDO. On September 27, 2021, FERC filed its brief with the D.C. Circuit Court of Appeals regarding the Jurisdictional PDO. On December 23, 2021, 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 March 23, 2022.

On April 30, 2021, we filed a proposed settlement agreement for approval with FERC 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 resolves 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 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. On August 2, 2021, FERC approved this settlement agreement. In December 2021, the administrative law judge adopted a procedural schedule on the four reserved issues with a hearing to occur in March 2022 and an initial decision to be issued by an administrative law judge by the end of May 2022.

On October 22, 2021, we filed a proposed settlement agreement for approval with FERC related to our transmission service rates, including our open access transmission tariff and annual transmission revenue requirements. The settlement resolves all issues set for hearing and settlement procedures related to our transmission service rates. The settlement agreement provides for us to refund amounts collected more than the amounts agreed to in the settlement agreement beginning March 26, 2020 upon FERC approval of the settlement agreement. We also filed a motion with FERC’s Chief Judge seeking authorization to implement our reduced transmission service rates and annual transmission revenue requirements for the 2021 rate year beginning on October 1, 2021 pending FERC approval of the settlement agreement. On October 28, 2021, the Chief Judge issued an order granting implementation of the proposed reduced settlement rates effective as of October 1, 2021 pending FERC’s consideration of the settlement agreement. On December 7, 2021, the Chief Judge terminated the settlement judge procedures for our transmission rates dockets. On March 7, 2022, FERC approved this settlement agreement. In connection with the settlement agreement, our other revenue and results of operations does not include our estimate of revenue that will be refunded. Such amount is being held in reserve.

It is not possible to predict the outcome of the four reserved issues related to our member rates docket or if FERC will require us to refund amounts related to the one reserved issue regarding transmission demand charges applicable to certain electric storage resources. 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 proceeding into one, 19F-0621E.

A hearing was held on May 18-20, 2020. On July 10, 2020, the administrative law judge issued a recommended decision, but the COPUC on its own motion stayed the recommended decision. On September 18, 2020, LPEA and United Power filed a Joint Motion to Lodge FERC’s August 28 Order, and asserting 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. It is not possible to predict the outcome in this matter.

United Power's Adams District Court Complaints: On May 4, 2020, United Power filed a Complaint for Declaratory Judgement and Damages with the Adams County District Court, 2020CV30649, against us and our three Non-Utility Members alleging, among other things, that the April 2019 Bylaws amendment that allows our Board to establish one or more classes of membership in addition to the then existing all-requirements class of membership is void, the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula are also void, that we have breached the wholesale electric service contract with United Power, and that we and our three Non-Utility Members conspired to deprive the COPUC of jurisdiction over the contract termination payment of our Colorado Utility Members. On June 20, 2020, we filed our answer denying United Power’s allegations and request for relief, and asked the court to dismiss United Power’s claims. We asserted counterclaims against United Power, and are seeking 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 June 20, 2020, the three Non-Utility Members filed a joint motion to dismiss.

On December 10, 2020, the Non-Utility Members motion to dismiss was granted. On December 23, 2020, United Power sought to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add a claim that our addition of the Non-Utility Members violated Colorado law. On July 2, 2021, the court granted United Power's motion to amend its May 2020 complaint, including to add LPEA as an additional plaintiff and to amend its claims as to our three Non-Utility Members. On July 30, 2021, we filed a partial motion to dismiss a majority of United Power's and LPEA's claims, including claims related to the April 2019 Bylaws amendment, the April 2020 Board approvals, and that we conspired with our Non-Utility Members. On July 30, 2021, the three Non-Utility Members filed a joint motion to dismiss all claims by United Power and LPEA against the Non-Utility Members. 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 with 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. A jury trial is scheduled for April 2023. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

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. 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 January 25, 2022, we filed a motion to dismiss. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

NOTE 16 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 9, 2022, which is the date when the financial statements were issued.

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