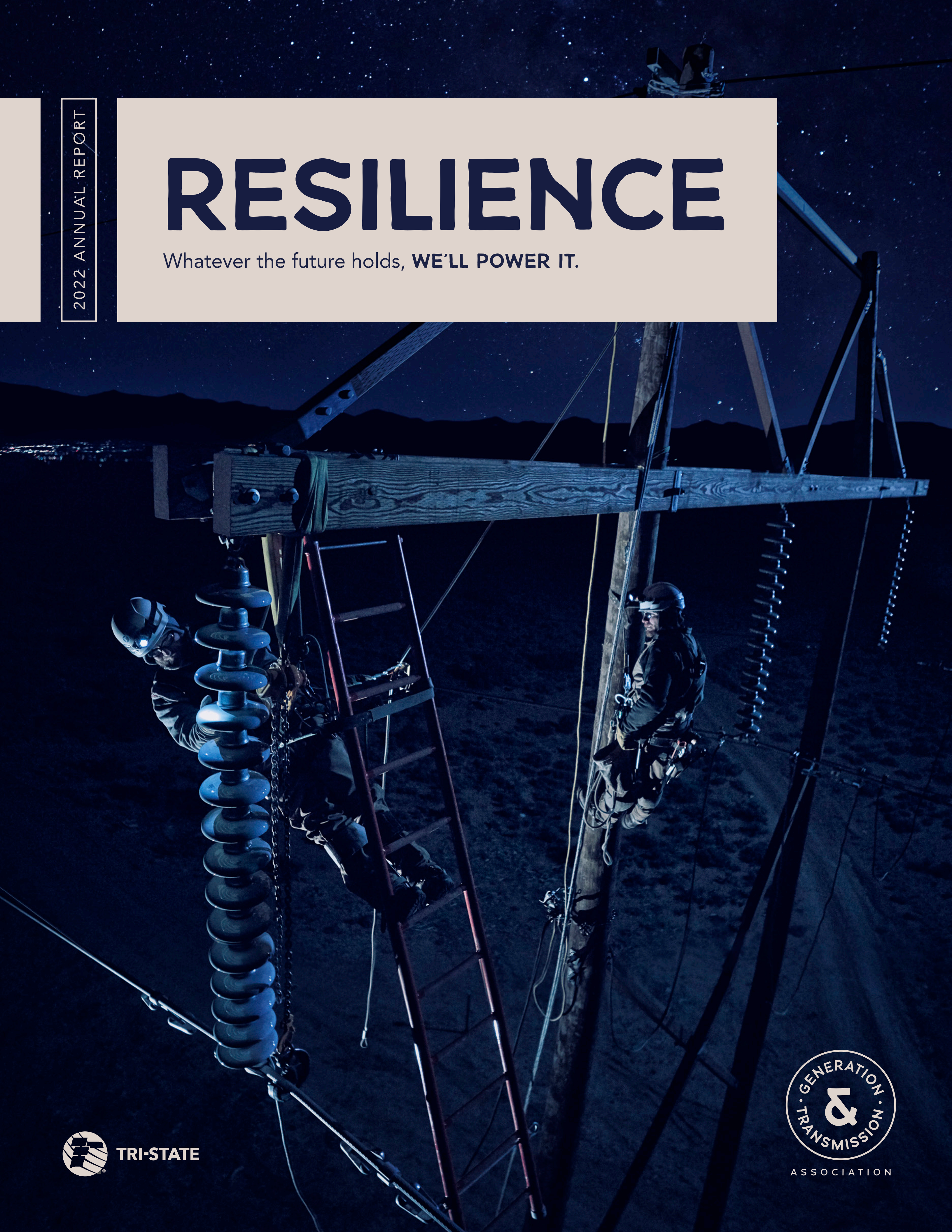


2022 ANNUAL REPORT

RESILIENCE

Whatever the future holds, **WE'LL POWER IT.**

TRI-STATE

GENERATION & TRANSMISSION ASSOCIATION

THE WOOD TEXTURE FEATURED THROUGHOUT THIS REPORT COMES FROM A 115kV TRANSMISSION POLE IN YUMA, CO. MOST POLES FROM THIS LINE HAD A MANUFACTURING DATE OF 1956, ALMOST AS OLD AS TRI-STATE ITSELF.

OUR PATH OF RESILIENCY BEGAN OVER 70 YEARS AGO.

"The practice has been too frequent in the past for private utility companies to undertake to serve only the more prosperous and more populous rural sections. As a result, families in less favored and in sparsely settled sections were left unserved. I believe that our postwar rural electrification program should bring modern service of electric power to the farm families in the back country."

- FRANKLIN D. ROOSEVELT SPEAKING ON THE RURAL ELECTRIFICATION ACT

Rather than waiting for others to electrify rural America, western communities took the future into their own hands, creating electric cooperatives to bring innovation and prosperity on their own terms. In 1952, our members came together, combining their strength to create Tri-State as their wholesale power supplier. Today, we serve our mission to deliver reliable, affordable and responsible power in accordance with cooperative principles. Central to our success in serving our mission, across more than 70 years, is the resiliency of our cooperative business model. Through democratic processes and transparency, our members lead us to ensure stability as we leverage opportunities and manage the risks of power supply. As the landscape of energy changes, Tri-State's resiliency, even as we transition, ensures we will always be here to serve.

Whatever the future holds, we'll power it.

LETTER FROM THE CHAIRMAN

Resiliency across all aspects of our cooperative ensures Tri-State always serves our mission to deliver reliable, affordable and responsible power to our members. The founders of our cooperative movement were a resilient lot, and in that tradition we have not, and will not, shy away from our responsibilities as we work with our membership to power the West.

Our continued success centers on our board and members, as they work together in a constructive and respectful manner, empowered by transparency and a voice in the decisions of this cooperative. Our cooperative governance model stands tall and remains unique in our electric utility industry, driving our decisions on operations, finances, rates and contracts, and the future we share as members of Tri-State.

Notably in 2022, our Rate Design Committee made significant progress in the difficult work to recommend how we calculate our wholesale rates, and our board and membership continued to advance greater contract flexibility, while protecting the interests of all members and Tri-State.

While our nation is challenged with high inflation, Tri-State maintained our financial strength, and we are positioned to maintain our seven years of wholesale rate stability with no increase through 2023. We are an increasingly competitive power supplier for our members, with full implementation of a 4% wholesale rate reduction that has saved our members $62 million over the past two years, and the return to our members of $10 million in patronage capital in 2022.

And even with our focus on Tri-State's energy transition, I remain confident that our board and management will never lose sight of our priorities of reliability and resilience. Power remains the lifeblood of the West, and we will advance every front to deliver on our members' expectations.

Thank you to the board, the membership and staff for their diligent work to continue to navigate through this time of change and challenges, with a focus on our mission, cooperation and progress.

Tim Rabon, Chairman

"OUR MEMBERS PROVIDED THE DIRECTION AND SUPPORT THAT ENSURES THAT TRI-STATE WILL BE STRONGER THAN EVER BEFORE, AND WILL CONTINUE TO BE SO WELL INTO THE FUTURE." -TIM RABON

LETTER FROM THE CEO

Progress comes from recognizing when you can't achieve your goals alone, and that's part of the beauty of the cooperative business model. By working together, not only as a cooperative, but as part of a broader community passionate about those we serve and the critical product we provide, we have continued to define our resilient path for the future.

In 2022, we certainly weren't the only electric utility impacted by the higher costs of fuel and power, rising inflation and supply chain challenges, but uniquely among most utilities, our preparations and planning allowed us to lower wholesale rates for our members, while maintaining our investment grade credit ratings, strong liquidity and access to capital.

As a cooperative, our purpose can't be matched – working with our members to make Western lives better. So even when we face a challenging year, we have the foundation we need to make adjustments and keep moving forward. In 2022, we aligned our management team and staff to best serve our members. We enhanced our efficiencies and preparations for the future, while continuing to meet the needs of the moment. Our employees safely work to ensure our members' assets, including our diverse generation portfolio, vast transmission system and capable energy management systems keep the lights on.

Collaboration remained a focus as we continued to work with stakeholders, reaching an important settlement on our 2020 electric resource plan, advancing cooperative provisions in federal legislation, and engaging with federal, state and local leaders in support of a just transition for our coal-dependent communities.

As we look to the future, our efforts continue to be focused on reliability as we rapidly transform our operations in a dynamic environment. We're actively pursuing participation in a Western regional transmission organization, acknowledging the greater reliability and affordability available when we pool our resources to meet clean energy and emissions reduction goals.

Our mission continues to drive us forward, and we know we're stronger and more resilient when we work together in the spirit of cooperation to achieve it.

Duane Highley, Chief Executive Officer

OUR MISSION IS TO PROVIDE OUR MEMBER SYSTEMS A RELIABLE, AFFORDABLE AND RESPONSIBLE SUPPLY OF ELECTRICITY IN ACCORDANCE WITH COOPERATIVE PRINCIPLES.

POWERING THE WEST SINCE 1952

Since our founding, it's been clear that by bringing reliable, affordable electricity to our members, we can help to open up the limitless potential that exists within rural communities. And the value of electricity continues to grow as the benefits of electrification are broadly recognized.

To deliver this valuable product, cooperatives work together, building the connections and the systems that can withstand even the greatest of challenges. In 2022, we saw upheaval from inflation, global unrest and disruption of supply chains; but our members' core need from Tri-State – for reliable, affordable and responsible electricity – is unchanged, as is our commitment to that mission.

Despite the challenges, Tri-State remains resilient and has continued to make progress in our energy transition. Our members are driving our future direction, and we're finding opportunities for collaboration, led by our members and engaging with stakeholders along the way. Together we are developing support and seeking solutions that benefit those we serve. We've worked at all levels:

- Industrywide efforts to represent the interests of rural communities as laws are passed and rules are made.
- Regional efforts to work toward a western energy market that can integrate more renewable generation and optimize the most affordable power sources available at each moment.
- Community-level efforts to support Tri-State members who want more local power generation and advances like electric vehicle charging infrastructure.
- Consumer-level efforts to make efficient electric products more accessible to all.

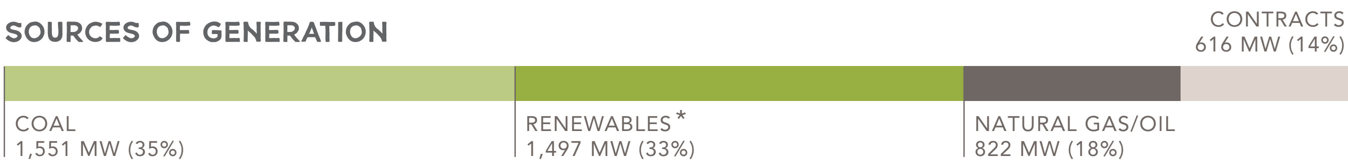
COLLABORATION HAS ALWAYS BEEN A REQUIREMENT IN OUR INDUSTRY, AND BY WORKING TOGETHER WE CONTINUE TO BOLSTER NOT ONLY THE RESILIENCE OF OUR BUSINESS MODEL, BUT ALSO THE STRENGTH OF OUR CONNECTIONS.

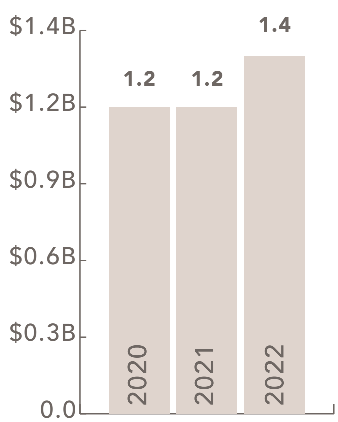
QUICK FACTS AND FINANCIALS

$1.5B operating revenue	**7.3¢/kWh** average member wholesale rate	**1,497 MW** renewable energy generation*
$62.6M saved by members through wholesale rate reductions	**$10M** patronage capital returned to members in 2022	**$4.9B** total assets

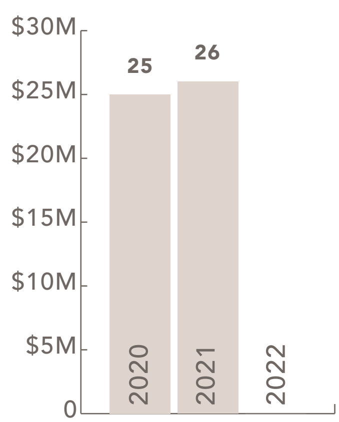
18.6M MWh TOTAL ENERGY SOLD

SOURCES OF GENERATION

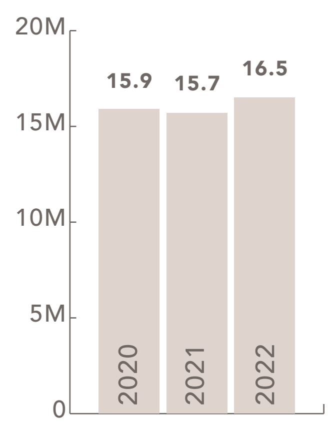




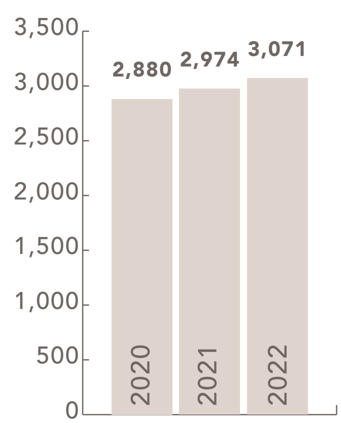
OPERATING EXPENSES



NET MARGIN**



ENERGY SOLD TO MEMBERS (MWh)



MEMBER COINCIDENT PEAK DEMAND (MW)

*This figure includes 131 MW of operating member renewable projects as of 12/31/22.

**Tri-State's board of directors adjusted our financial goals policy to allow for zero margins in 2022 to preserve rate stabilization efforts through 2023.

FINANCIAL RESILIENCE

RESPONSIBLY MANAGING OUR MEMBERS' RESOURCES

To best serve our members, Tri-State remains financially resilient and an increasingly competitive power supplier. In a challenging year, with dramatically increasing costs for purchased power and fuel, rising inflation, supply chain challenges and the lingering effects of the pandemic, we were able to do what G&Ts do best – mitigate risks and volatility while also delivering lower wholesale rates to our members. Tri-State's board of directors adjusted our financial goals policy to allow for zero margins in 2022 in order to preserve our rate stabilization efforts though 2023. Our positive operating cash flows and strong liquidity helped us maintain our coverage ratios, allowed us to return capital to members and supported our investment grade credit ratings.

- **Reducing wholesale rates:** Tri-State reduced wholesale rates to members by 2% in 2022, following a previous 2% wholesale rate reduction in 2021. The rate reduction has resulted in a total savings of $62.6 million for Tri-State members between March 2021 and the end of 2022, and Tri-State's wholesale rates for members were lower in 2022 than in 2017.

- **Advancing a new wholesale rate:** A Rate Design Committee of our membership worked diligently throughout 2022 to make a recommendation to our board of directors for a new wholesale rate design to be filed with the Federal Energy Regulatory Commission.

- **Patronage capital returned:** In 2022, Tri-State's board approved the return of $10 million in patronage capital, allocated in 2004, to our members. Tri-State has returned patronage capital for 40 consecutive years.

- **Strong liquidity:** Tri-State's liquidity is bolstered by a $520 million credit facility, supported by a large number of quality financial institutions, which helps us finance working capital, capital projects and provides us greater flexibility to plan for the future.

In an environment with increasing costs that affect not only our operations, but also our clean energy transition, Tri-State took meaningful steps to ensure our members have an affordable power supply.

- **Proactive management of costs:** In 2022, we continued our cost-reduction efforts with the active participation of employees to identify and implement cost-saving measures. Our ongoing enterprise resource planning software implementation will provide us with more aligned data and modernized processes to optimize business decisions.

- **Mitigating impacts of higher costs industrywide:** We experienced higher purchase power and fuel costs, as well as significant price increases for materials and services due to supply chain issues and inflation. We've mitigated these factors where we can by collaborating with peers, leveraging vendor relationships, and adjusting our processes, planning and timelines where appropriate.

- **Pursuing federal funding opportunities:** Tri-State led efforts to include cooperative clean energy provisions in legislation and engaged closely with federal, state and local leaders. We thoroughly evaluate all opportunities to leverage funding to support our work to harden the grid, increase clean energy solutions and support rural communities.

We continue to benefit from having a single rate regulator, the Federal Energy Regulatory Commission, as we work through important issues related to wholesale rates and flexibility in our wholesale electric service contracts with our utility members. During 2022, we worked through multiple FERC processes and brought on staff to help make our participation in these efforts as effective as possible.

ACTIVELY PARTICIPATING IN DEVELOPMENT OF LEGISLATION IMPACTING ELECTRIC COOPERATIVES AND RURAL COMMUNITIES

Inflation Reduction Act: Tri-State led efforts in collaborating with federal policymakers, cooperatives, environmental non-governmental organizations and other stakeholders to develop cooperative clean energy provisions in the Inflation Reduction Act of 2022, resulting in nearly $10 billion in funding options, as well as a direct pay tax option for clean energy tax credits for electric cooperatives. We have also been engaged with the Administration, including the U.S. Department of Agriculture, on how programs will be developed to allocate cooperative provision funds that support the energy transition. We will pursue these funds in support of a cost-effective clean energy transition for our membership.

INDUSTRY INFLATION SINCE 2020

↑50%	COPPER
↑60%	ALUMINUM
↑500%	OCEAN FREIGHT
↑34%	DOMESTIC FREIGHT
↑35%	TRANSFORMERS
↑40%	CONTROL BUILDINGS

Additionally, conductor prices for transmission lines have increased dramatically. It costs Tri-State $2 million more to buy the same footage in 2022 as it did the previous year and steel poles have increased more than $2 per pound.

OUR RESPONSE

For the utility industry, this plays out in price uncertainty and volatility, which can impact timelines for projects and the vendors utilities are using. With this in mind, Tri-State is taking the following actions to stay resilient, continue to deliver reliable and affordable electricity, and minimize impacts to our operations:

- We are preparing to evaluate bids faster as vendors allow a shorter time frame for bid acceptance.
- We are continuing to consider the right vendors for our needs while focusing on quality control.
- We are leveraging existing vendor relationships and evaluating vendor performance.
- We are increasing our inventory of critical parts and reaching out to counterparts at other G&Ts.
- We are planning projects earlier.

OPERATIONAL RESILIENCE

MAINTAINING THE SYSTEMS THAT KEEP THE LIGHTS ON

Our members count on us for a reliable supply of electricity, and that responsibility is our first priority. That's why we maintain a diverse set of generation resources that deliver power even with the most extreme weather, and we're constantly making the near-term and long-term decisions that help us deliver on our promises today and pave the way for continued reliability well into the future. We maintain and strengthen our generation and transmission facilities to serve our members' requirements, base our resource planning processes on sound modeling and achieve greater efficiencies through power markets – all so we can continue to be the power provider our members can always depend.

- **Advancing resource planning:** In 2022, our landmark, uncontested settlement with more than two dozen parties, including our members, state agencies, environmental non-governmental organizations, industry and labor, on Phase I of our 2020 Electric Resource Plan was approved by the Colorado Public Utilities Commission. Our resource planning ensures Tri-State can maintain reliable and affordable power as we responsibly implement our clean energy transition.

- **Growing renewables portfolio:** Tri-State currently has under contract more than 700 megawatts of solar resources to be added by 2025, and we issued a request for proposals in May 2022 for new renewable, storage and hybrid technology resources for 2025-2026 emissions-free generation. While the western drought has reduced the amount of federally marketed hydropower, more than one-third of the energy Tri-State members used in 2022 came from clean sources, and Tri-State set a renewable energy penetration peak of 1,245 megawatts in July 2022.

- **Participating in organized power markets:** Organized electricity markets play a vital role in integrating renewables, supporting the reliability of the region's transmission system and meeting demand with the most cost-effective generation available. Tri-State operates in two energy imbalance markets and in the Southwest Power Pool regional transmission organization in the Eastern interconnect. We continue to advance efforts that would allow us to participate in a regional transmission organization market in the West, including work on the proposed expansion of the Southwest Power Pool into the Western interconnect.

CLEAN POWER

WE'RE ADDING MORE THAN 700 MEGAWATTS OF SOLAR BY 2025

WILDFIRE MITIGATION

TRI-STATE HAS 300+ MILES OF VEGETATION MANAGEMENT PROJECTS ONGOING AND PLANNED THROUGH 2026

COMMITTED TO MEMBER NEEDS

In 2022, Tri-State remained focused on ensuring our transmission network remained reliable and resilient to meet our members' needs.

- **Serving our members' needs:** One of the benefits of Tri-State membership is our ability to plan for and serve our members' power needs. In 2022, Tri-State completed construction projects at 30 new or expanded delivery points to serve members' growth and reliability needs.
- **Transmission expansion:** We secured necessary state approvals to build new transmission lines and other transmission upgrades in eastern Colorado that will improve system reliability, strengthen our interconnected network and support connecting to 700 megawatts of new renewable capacity.
- **Addressing wildfire risk:** The increased frequency and intensity of wildfires reinforces the importance of mitigating wildfire ignition risks to ensure reliability, sustainability and natural resource preservation. Tri-State assesses where important maintenance activities, such as vegetation management, should be prioritized, and completed a major vegetation management project in southwest Colorado that supports reliability and mitigates wildfire risk. Tri-State remains focused on working with other utilities and federal land management agencies to improve the process for securing permits in utility rights-of-way.

RESILIENT SYSTEMS

MANAGING INDUSTRY RISKS AND RESPONDING

Part of maintaining a reliable power supply is being highly aware of the challenges to delivering reliable power, managing risks that could impact the system, and constantly working to assess those risks, build protections, conduct drills and constantly improve our plans.

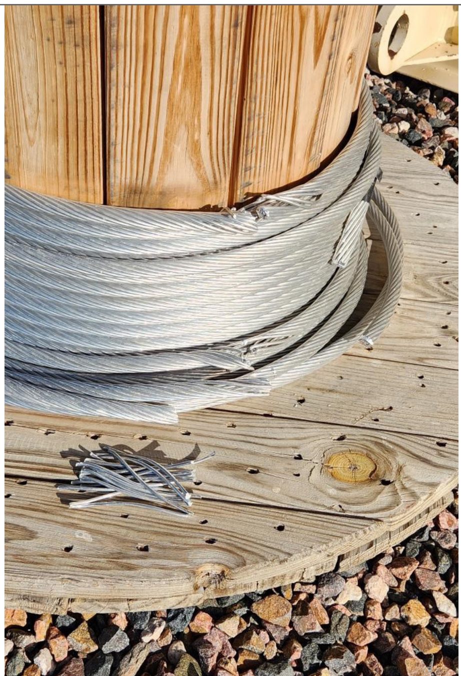
- **COVID-19 response:** During the COVID-19 pandemic, Tri-State appointed an incident commander who directed a team on new procedures, processes, actions and requirements so Tri-State could maintain operations that were as close to normal as possible. Some of the challenges sparked during 2020 – like supply chain issues and vigilance around employee health – persisted into 2022, and our organization continues to meet those challenges, respond and adjust so we can continue to serve our members.

- **Extreme weather:** Whether it's record-breaking heat or extreme cold, our teams have plans they enact when the weather gets especially challenging. Grounded with the diversity of our resources, our robust transmission system and energy management systems, Tri-State's extreme weather plan was tested in both heat and cold in 2022, with teams ensuring we were as prepared as possible with adequate resources to meet the demand for power.

Tri-State proactively protects our critical infrastructure, ensuring the reliable power our members depend on.

- **Cybersecurity:** Tri-State's Cyber Security Program is continually maturing to adapt to the latest threats in the electric utility industry. We perform annual evaluations of our controls relative to industry-recognized frameworks, and we use controls to identify gaps that may exist. We maintain a Cyber Security Center, which provides centralized monitoring, reporting and incident response for cyber security events. To ensure preparedness, in 2022, we conducted a thorough, multi-disciplinary simulation of a cyber security incident.

- **Physical threats:** Bulk power transmission organizations are a heavily regulated industry that strictly comply with all North American Electric Reliability Corp. (NERC) security standards. Substations and other grid equipment are assessed based on criticality, and then protected with security measures that match the risk. We work closely with federal, state and local partners to respond to security events, such as participating on the Electricity Subsector Coordinating Council (ESCC).



DETERRING PHYSICAL THREATS

In response to multiple copper theft incidents at substations in northeastern Colorado, Tri-State, other regional utilities and county sheriff's departments collaborated in 2022 to discuss potential mitigation strategies. The group focused on deterrence as well as surveillance.

In September, after weeks of surveillance work, the Yuma and Washington County Sheriff's Offices apprehended two people in connection with copper theft at Tri-State's substations. It is a felony to tamper with or disrupt transmission facilities.

RESILIENT COMMUNITIES

EMPOWERING CONSUMERS WITH EFFICIENT, CLEAN TECHNOLOGIES

With our members, Tri-State is expanding the benefits of a clean grid through the advancement of electrification and energy efficiency. When designing electrification programs, Tri-State considers how these efforts will lower energy costs for consumers, improve their quality of life, reduce emissions and increase grid resilience. Our powerful electrification and efficiency programs drive the achievement of this goal.

- **Wise use of energy:** In addition to helping our members electrify, Tri-State's programs also support the efficient and wise use of energy. In 2022, these programs have helped our members conserve approximately 279,316 megawatt-hours of electricity over the lifetime of the equipment installed.
- **Efficiency savings targets:** Through the settlement on Phase I of our 2020 Electric Resource Plan, Tri-State established incremental annual energy efficiency savings targets for Colorado member load of at least 0.35% in 2023, 0.5% by 2024, 0.75% by 2025 and 1% by 2030.
- **Demand response:** Tri-State initiated development of a demand response platform and programs designed to control at least 4% of Colorado member peak load by 2025.
- **Supporting technology installations:** Through the heat pump Quality Install Program and rebates, Tri-State contributed to the installation of more than 940 air source heat pumps in 2022, with more than 72% of installs either replacing fossil fuel heat or added in new construction.

As we transition to cleaner generation resources, Tri-State is working with affected communities and local, state and federal officials to ensure a just transition for coal-dependent communities.

- **Advocating:** We identify and advocate for opportunities that support rural communities, engaging in the community and with Tri-State employees to support their goals.
- **Assisting impacted communities:** In partnership with state and local leaders, Tri-State is supporting facilitators to guide discussions exploring community assistance opportunities for the City of Craig and Moffat County, in preparation for the retirement of Craig Station by 2030.
- **Seeking available funding:** In December 2022, Tri-State announced funds for Craig to assist with future grant-writing efforts.
- **Boosting economic development:** Tri-State donated $50,000 for local economic development to the Rifle Regional Economic Development Corporation following the retirement of the 85-megawatt Rifle Generating Station in 2022.

RESILIENT PEOPLE

SUPPORTING THE TEAMS THAT SAFELY SERVE OUR MEMBERS

In 2022, Tri-State consolidated key executive-level roles under Operations and Administration, reorganizing teams and aligning them to optimize collaboration across the organization. The safety of our employees and those we serve remains our core value, and we further bolstered our safety culture. In addition, we continued to support and develop our people, while empowering them to help shape the Tri-State of the future.

- **Safety Vision:** In 2022, Tri-State rolled out our Safety Vision and the behaviors for employees and leaders to enact as we support our safe work environment.
- **Safety recognition:** Multiple groups and facilities were recognized with safety awards in 2022, including:
    - National Safety Council perfect record awards for no occupational injuries or illness involving days away from work during the year
    - Colorado Mining Association awards for outstanding safety performance at Colowyo Mine and excellence in individual safety for two employees who reached 30 years without injury
    - National Safety Council awards for Superior Safety Performance – 10 or more consecutive safe years – for Burlington Station, Rifle Generating Station and Pyramid Generating Station

Escalante Station completed its final year as a New Mexico OSHA Voluntary Protection Program (VPP) participant in February 2022. Escalante has voluntarily withdrawn from future VPP participation due to the non-operational status of the plant but will continue to maintain its exemplary safety programs according to the VPP model as long as Tri-State manages the facility.

OUR SAFETY VISION

We attend to the safety of our employees, our contractors, and our communities before all other priorities. We aspire to prevent all fatalities and all serious injuries. We put the protection of human life and the prevention of injuries above all else.

EMPOWERING EMPLOYEES

- **Skill development:** In 2022, we offered employees change management training, completed another successful session of our Leadership Development Program, and brought together the alumni of all previous leadership classes to continue to connect and collaborate.
- **Listening:** Tri-State employees have been empowered to bring forward cost-savings opportunities as they identify them. Employees are also regularly invited to provide feedback to Tri-State on what we're already doing well as an organization and where we can continue to improve.
- **Apprenticeship programs:** We continue to offer apprenticeship programs for roles such as line technicians, substation and apparatus technicians, telecommunications technicians, vehicle mechanics, combined cycle technicians/operators, and more. This program develops candidates into productive journey-level employees. In 2022 we had 75 apprentices, and 19 graduated to journey level.


RELIABLE
AFFORDABLE
RESPONSIBLE
FLEXIBLE

NAVIGATING CHALLENGES WHILE MAINTAINING RELIABILITY

IN 2022

TRI-STATE LINEWORKERS REPLACED 345 H-FRAME 2-POLE STRUCTURES

Barry Ingold, Chief Operating Officer, leads Tri-State's Generation, Energy Markets and Transmission groups. In 2022, Barry focused on the big picture of team collaboration and process efficiencies as he led these teams with a strong alignment and common purpose.

BARRY INGOLD

HOW WAS 2022 OPERATIONALLY FOR TRI-STATE?

Even though 2022 was a challenging year overall, Tri-State was able to benefit from the fact that we have a well-balanced system. Because we can draw on our coal fleet, our natural gas and fuel oil fleet and our renewables fleet to meet our members' demand, we had the flexibility to make adjustments as needed during times of extreme weather or higher demand to maintain reliability.

Our Energy Markets team made the call on when it made sense to buy energy on the market or sell into the market as opportunities presented themselves. And our Transmission team maintained an excellent level of system reliability throughout the year. The performance of our teams and the strength of the leadership within our Generation, Energy Markets and Transmission areas continued to show that we have the expertise and dedication to respond to any challenges we face.

HOW DOES TRI-STATE STAY RESILIENT DURING BOTH NORMAL OPERATIONS AND WHEN THE SYSTEM IS STRESSED BY WEATHER EXTREMES?

At the simplest level, Generation makes the power and works with Energy Markets to balance generation with the load, so that Transmission can deliver it. In 2022, I took on the oversight of each of these teams, and together we've identified even more opportunities for collaboration and efficiencies across the groups.

We were fortunate that 2022 was a year that didn't see the same kind of major storm damage similar to what we experienced in the few years prior. But we did have our fair share of weather extremes that tested the system. In those instances, our established processes kicked in: we watched for the upcoming extreme weather, made adjustments as needed to have plants already running or ready to run, secured sufficient fuel supply, and halted any activities that could potentially impact system reliability. In the heights of extreme weather, we kept the lights on for our members.

AS TRI-STATE ADDS MORE INTERMITTENT RESOURCES LIKE WIND AND SOLAR POWER, DOES THAT IMPACT THE RELIABILITY OF THE ELECTRICITY TRI-STATE PROVIDES?

Intermittent resources can create a challenge on a cold winter night when the sun doesn't shine and the wind doesn't blow. But this is something we prepare for. As we work through our Electric Resource Plan to ensure resource adequacy, we take into account the values and limitations of each different source of power.

We have power purchase agreements for new solar resources to come online in 2024 and received a strong response to a request for proposals we issued in 2022 for new renewable, storage and hybrid technology resources for emissions-free generation. We also advanced our efforts to build new transmission lines and other transmission upgrades that will support connecting new renewable resources, bolster our ability to move power and improve system reliability.

Our diverse mix of generation sources keeps us reliable during all times of the year, and we are committed to maintaining the reliability and performance of our generation fleet while we're transitioning to more renewables.

WHAT ARE SOME OF THE KEY THINGS YOU'RE LOOKING AHEAD TO IN 2023?

I'm looking forward to continuing to improve internal efficiency and remaining laser-focused on serving our members' needs. We're rolling out new technologies that will improve our business processes within Tri-State, and on a broader scale we're also working toward participation in a regional transmission organization: each of these efforts will give us added efficiencies.

Overall, I'm focused on the preparations we're putting in place to ensure we're meeting the commitments we laid out in our Responsible Energy Plan. We've made great progress on that plan, and are continuing to drive toward our goals.

"THE RESILIENCE OF OUR TEAMS THROUGH THESE CONSTANT CHANGES HAS ALWAYS IMPRESSED ME. THEY'RE DEDICATED TO THE GOAL - MAKING THE ELECTRICITY THAT POWERS OUR MEMBERS AND THEIR COMMUNITIES."

- BARRY INGOLD

BRINGING MEMBER VALUE THROUGH ENERGY INNOVATIONS

Reg Rudolph, Chief Energy Innovations Officer, launched an energy innovations team in 2022 to develop pathways for consumers to reduce their energy burden and emissions, with a focus on efficient electrification.

ELECTRIFICATION EFFORTS IN 2022

$1.7 MILLION TO SUPPORT HEAT PUMP INSTALLS

$268,000+ TO SUPPORT EV CHARGING INFRASTRUCTURE

30% INCREASE IN HEAT PUMP INSTALLS

WHY IS ENERGY INNOVATIONS IMPORTANT TO TRI-STATE?

When I look at energy innovations opportunities at Tri-State, there are really two drivers: the benefits these opportunities bring to our members and their end-use consumers, and the role they play in helping us meet our energy resource plan goals.

Value for members: We want to save our members and their end-use consumers money. These savings can come from using the least amount of energy to get the job done, using energy at the time it is most affordable, and switching from higher-cost, higher-emissions fuels to electricity where it makes the most sense. The services we're building play into each of these goals.

Satisfying electric resource plan goals: We serve members across four states and comply with the various rules and regulations of all. We have a 2020 energy resource plan settlement in Colorado that includes energy efficiency and demand response requirements that we are committed to meet, and the actions we are taking will benefit all members. The solutions we are building to help support energy efficiency, from marketing support, to rebates for energy-efficient appliances and products, as well as opportunities for on-bill repayment for consumers who purchase those items, get us closer to meeting those requirements.

"TRI-STATE CAN WORK WITH ITS MEMBERS, ROOTED IN DATA AND ANALYTICS, TO OPTIMIZE HOW WE BEST UTILIZE OUR ENERGY SYSTEMS, REDUCE COSTS, INCREASE REVENUES AND MAKE A DIFFERENCE FOR ALL OF OUR MEMBERS."

- REG RUDOLPH

HOW DOES INCREASING ELECTRIFICATION IMPACT THE RESILIENCE OF THE GRID?

The ultimate goal is to build an efficient smart grid in coordination with our members. When more consumers use electricity to power their lives, it opens up the opportunity for enhanced integration with the consumer and improved optimization of how power is used. If electricity is in high demand, we can help to send a price signal and voluntarily control certain load in certain areas – balancing supply and demand in support of both affordability and the resilience of the system.

Extreme weather situations that strain the grid are an example of when it can be most impactful to coordinate the supply and demand functions. We're working together with our members to determine where we can enhance these grid connections and what it will take to build the functionality required to control load during these critical times.

WHAT KIND OF COLLABORATION IS NEEDED TO MOVE THESE ENERGY INNOVATIONS FORWARD?

I refer to the cooperative energy ecosystem as a way to describe the multiple elements we're looking to connect. This ecosystem includes everything from electric vehicles and rooftop solar, to microgrids and community solar and wind, and even battery storage and demand response.

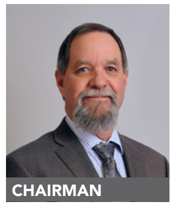
When we optimize the network to create a vertically-coordinated system, we can capture value for multiple parties at multiple levels. So, collaboration is really needed at all levels – from the wholesale power supplier to the distribution system to the end-use consumers and the vendors who sell products powered by electricity.

In addition to this collaboration, we're also closely involved with regulators and legislators as they develop and implement programs and rules that impact the electricity industry. For example, in 2022 we made progress toward on-bill repayment, offering end-use consumers the choice to pay for a new electric appliance over time through their electric bill. Support from our federal partners is now available to help us make this option more accessible, and we look forward to helping our members bring this value to their consumers.

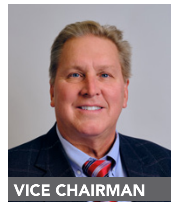
COMPONENTS OF THE COOPERATIVE ENERGY ECOSYSTEM:

- DEMAND RESPONSE
- ROOFTOP SOLAR
- BATTERY STORAGE
- WIND
- ELECTRIC & THERMAL STORAGE
- COMMUNITY SOLAR
- ELECTRIC VEHICLES
- COMBINED HEAT & POWER
- MICROGRIDS

OUR BOARD OF DIRECTORS


CHAIRMAN

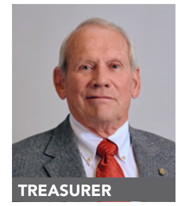
Tim Rabon
Otero County Electric


VICE CHAIRMAN

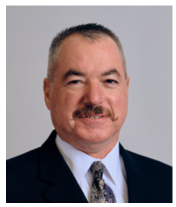
Don Keairns
San Isabel Electric


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

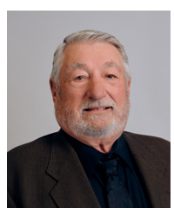
Lucas Bear
Northwest Rural Public Power

Jerry Fetterman
Empire Electric

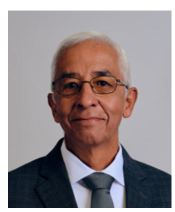
Jack Finnerty
Wheatland Rural Electric

Joel Gilbert
Southwestern Electric

Rick Gordon
Mountain View Electric



Stan Propp
Chimney Rock Public Power

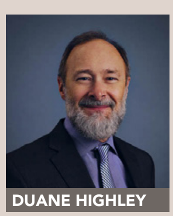


Steve Rendon
Northern Rio Arriba Electric

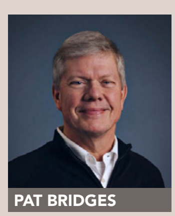
Peggy Ruble
Garland Light & Power

Roger Schenk
Y-W Electric

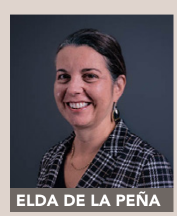
OUR EXECUTIVE TEAM


DUANE HIGHLEY

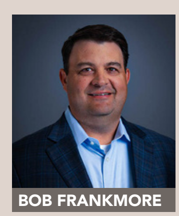
Chief Executive Officer


PAT BRIDGES

Senior Vice President and Chief Financial Officer


ELDA DE LA PEÑA

Chief Administrative Officer and CHRO

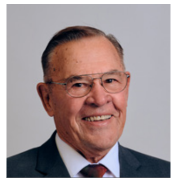

BOB FRANKMORE

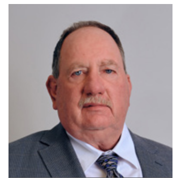
Chief of Staff


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

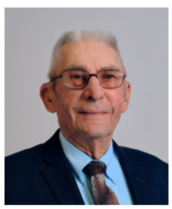

Kevin Cooney
San Miguel Power


Mark Daily
Gunnison County Electric

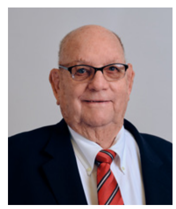

Bruce Duran
Jemez Mountains Electric


Randy Graff
Morgan County Rural Electric


Ron Hilkey
White River Electric


Ralph Hilyard
Roosevelt Public Power


Joe Hoskins
Continental Divide Electric


Hal Keeler
Columbus Electric


Brian McCormick
United Power


Kohler McInnis
La Plata Electric


Gary Shaw
Springer Electric


Darryl Sullivan
Sierra Electric

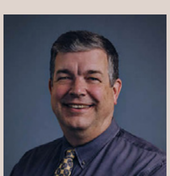

Kevin Thomas
High West Energy

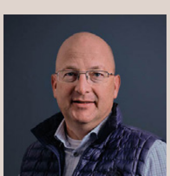

Clay Thompson
Carbon Power & Light

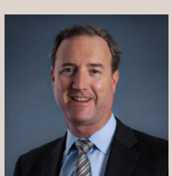

Carl Trick II
Mountain Parks Electric

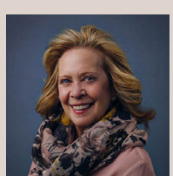

William Wilson
Niobrara Electric


Phil Zochol
Panhandle Rural Electric


BARRY INGOLD
Chief Operating Officer


REG RUDOLPH
Chief Energy Innovations Officer


JAY STURHAHN
Senior Vice President and General Counsel


BARBARA WALZ
Senior Vice President, Policy & Compliance, and Chief Compliance Officer

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

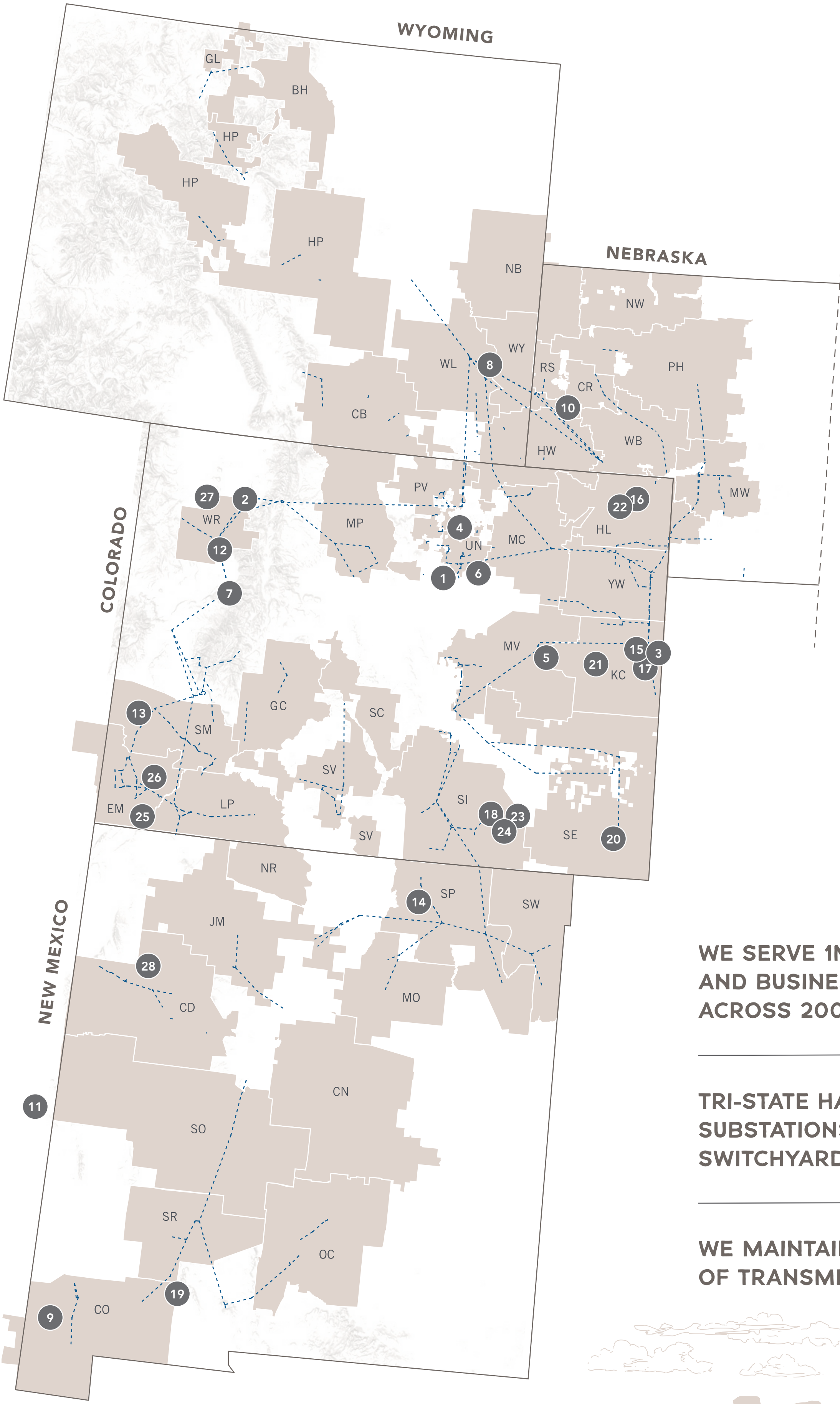
NON-UTILITY MEMBERS

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 (retired in 2022) – 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. Niyol Wind – Logan County, CO
23. Spanish Peaks Solar (2024) – Las Animas County, CO
24. Spanish Peaks II Solar (2024) – Las Animas County, CO
25. Coyote Gulch Solar (2024) – Montezuma County, CO
26. Dolores Canyon Solar (2024) – Dolores County, CO
27. Axial Basin Solar (2024) – Moffat County, CO
28. Escalante Solar (2024) – McKinley County, NM

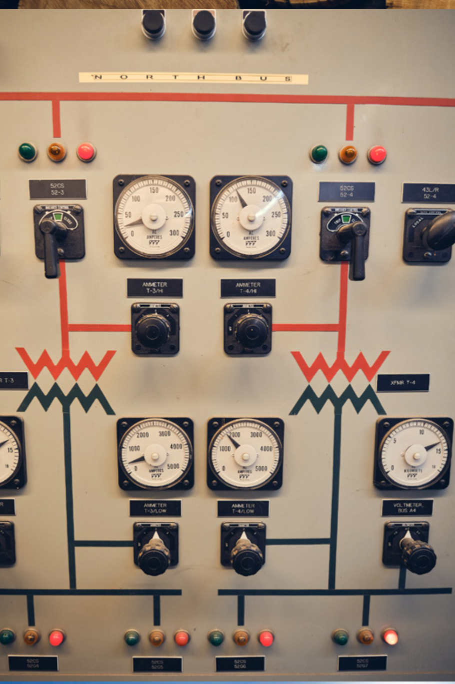
Tri-State also receives power from several small hydropower projects and under long-term contracts with the Western Area Power Administration and Basin Electric Power Cooperative.



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

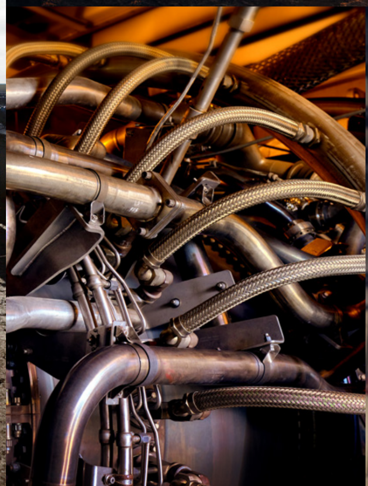
TRI-STATE HAS 400+ SUBSTATIONS AND SWITCHYARDS

WE MAINTAIN 5,849 MILES OF TRANSMISSION LINE


NORTH BUS


Friends of Coal


TRI-STATE




Columbia

WHATEVER THE FUTURE HOLDS,
WE'LL POWER IT.

MAKING THE COOPERATIVE DIFFERENCE

SINCE 1952

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.

TRI-STATE

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, 2022 and 2021, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 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 and Environmental Reclamation 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 management's estimated fair value at the time the obligations are incurred and capitalized as part of the related long-lived asset or reflected in earnings in the period an estimate is

revised, as applicable. As changes in estimates occur, such as mine plans, estimated costs and timing of reclamation activities, the Association makes revisions to the related obligation at the appropriate discount rate.

Auditing the Association's asset retirement and environmental reclamation 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 calculations of the asset retirement and environmental reclamation obligations 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 and environmental reclamation obligations 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 and environmental reclamation 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 10, 2023

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

	December 31, 2022	December 31, 2021
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,659,423	$ 5,606,732
Construction work in progress	81,555	107,636
Total electric plant	**5,740,978**	**5,714,368**
Less allowances for depreciation and amortization	(2,392,363)	(2,367,197)
Net electric plant	**3,348,615**	**3,347,171**
Other plant	954,144	1,093,922
Less allowances for depreciation, amortization and depletion	(694,774)	(823,087)
Net other plant	**259,370**	**270,835**
Total property, plant and equipment	**3,607,985**	**3,618,006**
Other assets and investments		
Investments in other associations	177,477	163,097
Investments in and advances to coal mines	1,914	2,273
Restricted cash and investments	4,257	4,101
Other noncurrent assets	15,828	15,873
Total other assets and investments	**199,476**	**185,344**
Current assets		
Cash and cash equivalents	105,852	100,555
Restricted cash and investments	573	480
Deposits and advances	34,233	34,042
Accounts receivable—Members	103,246	95,630
Other accounts receivable	32,436	21,571
Coal inventory	34,723	59,701
Materials and supplies	93,514	87,234
Total current assets	**404,577**	**399,213**
Deferred charges		
Regulatory assets	650,421	665,693
Prepayment—NRECA Retirement Security Plan	10,745	16,117
Other	40,445	35,139
Total deferred charges	**701,611**	**716,949**
Total assets	**$ 4,913,649**	**$ 4,919,512**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 984,865	$ 994,865
Accumulated other comprehensive loss	(468)	(1,460)
Noncontrolling interest	126,180	119,100
Total equity	**1,110,577**	**1,112,505**
Long-term debt	2,869,963	3,101,870
Total capitalization	**3,980,540**	**4,214,375**
Current liabilities		
Member advances	17,070	17,217
Accounts payable	109,109	105,965
Short-term borrowings	274,102	49,997
Accrued expenses	42,506	32,882
Current asset retirement obligations	5,419	7,003
Accrued interest	25,431	25,716
Accrued property taxes	36,477	33,877
Current maturities of long-term debt	92,920	93,039
Total current liabilities	**603,034**	**365,696**
Deferred credits and other liabilities		
Regulatory liabilities	49,931	146,021
Deferred income tax liability	19,275	18,987
Asset retirement and environmental reclamation obligations	181,588	83,278
Other	68,374	78,319
Total deferred credits and other liabilities	**319,168**	**326,605**
Accumulated postretirement benefit and postemployment obligations	10,907	12,836
Total equity and liabilities	**$ 4,913,649**	**$ 4,919,512**

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

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

	For the years ended December 31, 2022	2021	2020
Operating revenues			
Member electric sales	$ 1,213,234	$ 1,161,291	$ 1,196,232
Non-member electric sales	163,355	114,908	90,382
Rate stabilization	95,613	78,457	12,136
Provision for rate refunds	(51)	(10,196)	—
Other	61,420	56,341	53,545
	1,533,571	**1,400,801**	**1,352,295**
Operating expenses			
Purchased power	409,513	381,477	335,814
Fuel	329,046	236,089	234,844
Production	177,413	185,016	171,188
Transmission	175,889	182,327	170,933
General and administrative	79,640	57,243	69,796
Depreciation, amortization and depletion	184,047	190,237	185,243
Coal mining	9,899	5,323	11,691
Other	53,509	7,191	15,126
	1,418,956	**1,244,903**	**1,194,635**
Operating margins	**114,615**	**155,898**	**157,660**
Other income			
Interest	4,447	3,609	4,218
Capital credits from cooperatives	26,185	9,466	11,803
Other	10,027	4,152	1,831
	40,659	**17,227**	**17,852**
Interest expense			
Interest	148,609	143,328	151,423
Interest charged during construction	(1,486)	(3,786)	(6,088)
	147,123	**139,542**	**145,335**
Income tax expense (benefit)	(249)	295	(534)
Net margins including noncontrolling interest	**8,400**	**33,288**	**30,711**
Net margin attributable to noncontrolling interest	(8,400)	(6,942)	(5,590)
Net margins attributable to the Association	**$ —**	**$ 26,346**	**$ 25,121**

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, 2022	2021	2020
Net margins including noncontrolling interest	$ 8,400	$ 33,288	$ 30,711
Other comprehensive income (loss):			
Unrealized loss on securities available for sale	(333)	(108)	—
Unrecognized prior service credit on postretirement benefit obligation	—	5,698	—
Unrecognized actuarial gain on postretirement benefit obligation	32	784	625
Amortization of actuarial loss on postretirement benefit obligation included in net margin	102	78	—
Amortization of prior service credit on postretirement benefit obligation included in net margin	(1,636)	(2,139)	(79)
Unrecognized actuarial gain (loss) on executive benefit restoration obligation	1,740	(778)	(1,980)
Unrecognized prior service cost on executive benefit restoration obligation	(308)	(1,050)	(4,674)
Amortization of actuarial loss on executive benefit restoration obligation included in net margin	426	515	—
Curtailment and settlement	(187)	141	—
Amortization of prior service cost on executive benefit restoration obligation included in net margin	1,156	1,113	1,912
Other comprehensive income (loss)	**992**	**4,254**	**(4,196)**
Comprehensive income including noncontrolling interest	**9,392**	**37,542**	**26,515**
Net comprehensive income attributable to noncontrolling interest	(8,400)	(6,942)	(5,590)
Comprehensive income attributable to the Association	**$ 992**	**$ 30,600**	**$ 20,925**

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,		
	2022	2021	2020
Patronage capital equity at beginning of period	$ 994,865	$ 978,519	$ 1,031,063
Net margins attributable to the Association	—	26,346	25,121
Retirement of patronage capital	(10,000)	(10,000)	(77,665)
Patronage capital equity at end of period	**984,865**	**994,865**	**978,519**
Accumulated other comprehensive loss at beginning of period	(1,460)	(5,714)	(1,518)
Unrealized loss on securities available for sale	(333)	(108)	—
Reclassification adjustment for actuarial loss on postretirement benefit obligation included in net margin	102	78	—
Reclassification adjustment for prior service credit on postretirement benefit obligation included in net margin	(1,636)	(2,139)	(79)
Reclassification adjustment for actuarial loss on executive benefit restoration obligation included in net margin	426	515	—
Curtailment and settlement	(187)	141	—
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	1,156	1,113	1,912
Unrecognized prior service credit on postretirement benefit obligation	—	5,698	—
Unrecognized actuarial gain on postretirement benefit obligation	32	784	625
Unrecognized actuarial gain (loss) on executive benefit restoration obligation	1,740	(778)	(1,980)
Unrecognized prior service cost on executive benefit restoration obligation	(308)	(1,050)	(4,674)
Accumulated other comprehensive loss at end of period	**(468)**	**(1,460)**	**(5,714)**
Noncontrolling interest at beginning of period	119,100	114,851	111,717
Net comprehensive income attributable to noncontrolling interest	8,400	6,942	5,590
Equity distribution to noncontrolling interest	(1,320)	(2,693)	(2,456)
Noncontrolling interest at end of period	**126,180**	**119,100**	**114,851**
Total equity at end of period	**$ 1,110,577**	**$ 1,112,505**	**$ 1,087,656**

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,		
	2022	**2021**	**2020**
Operating activities			
Net margins including noncontrolling interest	$ 8,400	$ 33,288	$ 30,711
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	184,047	190,237	185,243
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,372
Amortization of debt issuance costs	3,105	2,479	2,460
Impairment loss	29,098	—	274,645
Deferred impairment loss and other closure costs	(29,098)	—	(283,047)
Deferred membership withdrawal income	—	—	110,165
Deposits associated with generator interconnection requests	6,716	17,130	—
Rate stabilization	(95,613)	(78,457)	(12,136)
Capital credit allocations from cooperatives and income from coal mines under (over) refund distributions	(14,115)	512	(1,268)
Changes in operating assets and liabilities:			
Accounts receivable	(30,135)	(3,618)	17,358
Coal inventory	24,978	(3,453)	(5,571)
Materials and supplies	(6,281)	(4,714)	(40)
Accounts payable and accrued expenses	19,102	13,114	(844)
Accrued interest	(285)	(1,804)	(2,196)
Accrued property taxes	2,600	1,082	3,665
New Horizon Mine environmental obligation	44,869	—	—
Other	(164)	(1,261)	6,402
Net cash provided by operating activities	**152,596**	**169,907**	**330,919**
Investing activities			
Purchases of plant	(121,527)	(118,422)	(142,152)
Sale of electric plant	—	—	26,000
Changes in deferred charges	(4,617)	(13,054)	(4,885)
Proceeds from other investments	94	72	733
Net cash used in investing activities	**(126,050)**	**(131,404)**	**(120,304)**
Financing activities			
Changes in Member advances	(282)	183	(7,837)
Payments of long-term debt	(232,946)	(94,288)	(282,757)
Proceeds from issuance of long-term debt	—	—	425,000
Debt issuance costs	(1,475)	—	(637)
Change in short-term borrowings, net	224,105	49,997	(252,323)
Retirement of patronage capital	(8,445)	(18,067)	(70,881)
Equity distribution to noncontrolling interest	(1,320)	(2,693)	(2,456)
Other	(637)	(573)	(418)
Net cash used in financing activities	**(21,000)**	**(65,441)**	**(192,309)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**5,546**	**(26,938)**	**18,306**
Cash, cash equivalents and restricted cash and investments – beginning	**105,136**	**132,074**	**113,768**
Cash, cash equivalents and restricted cash and investments – ending	**$ 110,682**	**$ 105,136**	**$ 132,074**
Supplemental cash flow information:			
Cash paid for interest	$ 145,350	$ 143,394	$ 152,570
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ (1,076)	$ 1,383	$ 440

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." Our rates are subject to regulation by the Federal Energy Regulatory Commission (“FERC”). On December 23, 2019, our stated rate to our Class A members was filed at FERC 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 14—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 2022, 2021 and 2020, total megawatt-hours sold were 18.6, 17.6 and 17.5 million, respectively, of which 88.8, 89.1 and 90.8 percent, respectively, were sold to Utility Members. Total revenue from electric sales was $1.4 billion for 2022 and $1.3 billion for 2021 and 2020 of which 82.4, 86.4, and 92.1 percent in 2022, 2021 and 2020, respectively, was from Utility Member sales. Energy resources were provided by our generation and purchased power, of which 54.3, 52.1 and 58.2 percent in 2022, 2021 and 2020, 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 1,105 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 13—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 were 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. In 2022, we recognized an impairment loss of $3.7 million associated with the early retirement of the Rifle Generating Station. We also recognized an impairment loss of $25.4 million associated with additional asset retirement obligations at the Nucla and Escalante Generating Stations related to a change in cost estimates. 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. 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 meet 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 13—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, 2022	December 31, 2021
Regulatory assets		
Deferred income tax expense (1)	$ 19,279	$ 18,742
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	76,842	79,133
Goodwill – J.M. Shafer (3)	40,598	43,447
Goodwill – Colowyo Coal (4)	34,095	35,128
Deferred debt prepayment transaction costs (5)	115,045	123,674
Deferred Holcomb expansion impairment loss (6)	79,470	84,145
Unrecovered plant (7)	285,092	281,424
Total regulatory assets	**650,421**	**665,693**
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	2,341	2,818
Membership withdrawal (9)	47,590	143,203
Total regulatory liabilities	**49,931**	**146,021**
Net regulatory asset	**$ 600,490**	**$ 519,672**

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(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 and other closure costs related to the early retirement of the Nucla, Escalante and Rifle Generating Stations. The deferred impairment loss for Nucla Generating Station was amortized to depreciation, amortization and depletion expense 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 $12.2 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 former annual Escalante Generating Station depreciation for the remaining life of the asset. In March 2022, our Board took action for the early retirement of Rifle Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement, we recognized an impairment loss of $3.7 million during the first quarter of 2022. The Rifle Generating Station was retired from service on September 30, 2022. The deferred impairment loss is being amortized to depreciation, amortization and depletion expense in the amount of $0.6 million annually through December 2028, which was the depreciable life of the Rifle Generating Station, and recovered from our Utility Members in rates.

(8) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12-

year term of the First Mortgage Obligations, Series 2017A and refunded to Utility Members through reduced rates when recognized in future periods.

(9) Represents the deferral of the recognition of other operating revenues related to the withdrawal of former Utility Members from membership in us. The deferred membership withdrawal income will be refunded to Utility Members through reduced rates when recognized in operating revenues in future periods. During 2022, $95.6 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 2.3 percent for 2022, 4.4 percent for 2021 and 4.6 percent for 2020. During 2022, Tri-State transitioned from using the "Indirect Costs" ("IDC") rate to the FERC prescribed "Allowance For Funds Used During Construction" ("AFUDC") rate. AFUDC is defined as the gross allowance for borrowed funds used during construction. The AFUDC rate is calculated with the assumption that short-term debt is the first source of funds used for construction. Any construction not covered by the short-term debt is then assumed to be covered by long-term debt. The AFUDC rate varies from the IDC rate, which assumes that total debt was used to cover construction costs. The amount of interest capitalized during construction was $1.5, $3.8 and $6.1 million during 2022, 2021 and 2020, 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 accrued expenses and the long-term portion of lease liabilities is included in other deferred credits and other liabilities on our consolidated statements of financial position. 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, 2022	December 31, 2021
Basin Electric Power Cooperative	$ 127,640	$ 116,826
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,172	12,076
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,054	15,149
CoBank, ACB	16,727	12,985
Other	5,884	6,061
Investments in other associations	**$ 177,477**	**$ 163,097**

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during 2022, 2021 or 2020.

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, 2022	December 31, 2021
Cash and cash equivalents	$ 105,852	$ 100,555
Restricted cash and investments - current	573	480
Restricted cash and investments - noncurrent	4,257	4,101
Cash, cash equivalents and restricted cash and investments	**$ 110,682**	**$ 105,136**

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 at December 31, 2022 were $0.6 million and $0.5 million, respectively. The cost and estimated fair value of the investments at December 31, 2021 were each $0.6 million.

INVENTORIES: Coal inventories at our owned generating facilities are stated at LIFO (last-in, first-out) cost and were $3.7 million and $27.1 million as of December 31, 2022 and 2021, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2022, we realized lower coal fuel expense of $14.5 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, 2022	December 31, 2021
Preliminary surveys and investigations	$ 13,048	$ 12,366
Advances to operating agents of jointly owned facilities	7,324	4,422
Operating lease right-of-use assets	6,771	7,529
Other	13,302	10,822
Total other deferred charges	**$ 40,445**	**$ 35,139**

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 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 $27.2 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 $18.6 million and $19.3 million as of December 31, 2022 and December 31, 2021, respectively, which is recorded as other deferred credits and other liabilities.

OATT deposits represent refundable transmission customer deposits related to interconnection and transmission requests from third parties. An OATT deposit is refundable should the interconnection or transmission request not move forward.

Financial liabilities-reclamation represent financial obligations that we have for our share of the reclamation costs at jointly owned facilities in which we have undivided interests in.

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, 2022	**December 31, 2021**
Transmission easements	$ 18,636	$ 19,339
OATT deposits	17,476	24,327
Financial liabilities - reclamation	12,429	13,122
Customer deposits	11,247	9,287
Contract liabilities (unearned revenue) - noncurrent	3,765	3,523
Operating lease liabilities - noncurrent	1,251	1,622
Other	3,570	7,099
Total other deferred credits and other liabilities	**$ 68,374**	**$ 78,319**

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. See Note 10—Revenue.

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. 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 $4.7 million and $2.9 million at December 31, 2022 and 2021, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was an expense of $1.5 million in 2022, an expense of $0.6 million in 2021 and a credit of $0.1 million in 2020.

ACCOUNTING PRONOUNCEMENTS - ADOPTED: In October 2021, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2021-10, *Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance.* The purpose of ASU 2021-10 is to increase the transparency of government assistance that is accounted for by applying a grant or contribution model by analogy, including disclosures of the types of assistance, the accounting for the assistance, and the effect of the assistance on an entity's financial statements. Prior to the issuance of ASU 2021-10, there was a lack of specific authoritative guidance in GAAP. This guidance excludes transactions in the scope of specific GAAP, such as tax incentives accounted for under Accounting Standards Codification ("ASC") 740, *Income Taxes.* ASU 2021-10 is effective for annual periods beginning after December 15, 2021, with early adoption and retrospective or prospective application permitted. We have evaluated the impact of adopting ASU 2021-10 and believe that the adoption of this update will not have a material impact on our consolidated financial statement disclosures.

RECLASSIFICATIONS: Certain reclassifications have been made to the prior year financial statements to conform to the 2022 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, 2022, 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 %	$ 3,048,918	$ (1,353,042)	$ 1,695,876
Transmission plant	1.11 %	to	2.09 %	1,956,378	(690,517)	1,265,861
General plant	1.46 %	to	9.53 %	412,879	(257,761)	155,118
Other	2.75 %	to	10.00 %	241,248	(91,043)	150,205
Electric plant in service (at cost)				**$ 5,659,423**	**$ (2,392,363)**	**3,267,060**
Construction work in progress						81,555
Electric plant						**$ 3,348,615**

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, 2022, we had $56.5 million of commitments to complete construction projects, of which approximately $19.6, $19.6 and $17.3 million are expected to be incurred in 2023, 2024 and 2025, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2022 (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 %	$ 391,689	$ 261,366	$ 163
MBPP - Laramie River Station	28.50 %	530,692	341,882	2,621
Total		**$ 922,381**	**$ 603,248**	**$ 2,784**

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 the Colowyo Mine, a surface coal mine near Craig, Colorado and the New Horizon Mine, near Nucla, Colorado. The New Horizon Mine is in post-reclamation monitoring and no longer produces coal. The expenses related to the Colowyo Mine 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, 2022	December 31, 2021
Colowyo Mine assets	$ 386,898	$ 376,868
New Horizon Mine assets	5,995	5,061
Accumulated depreciation and depletion	(155,653)	(133,951)
Net mine assets	**237,240**	**247,978**
Non-utility assets	561,251	711,993
Accumulated depreciation	(539,121)	(689,136)
Net non-utility assets	**22,130**	**22,857**
Net other plant	**$ 259,370**	**$ 270,835**

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. The New Horizon Mine is currently in post-reclamation monitoring. One pit at the Colowyo Mine began final reclamation in 2020 with the other remaining pits still being actively mined.

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

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

	2022	2021
Obligations at beginning of period	$ 90,281	$ 138,089
Liabilities incurred	—	1,475
Liabilities settled	(3,184)	(4,934)
Accretion expense	6,163	2,409
Change in estimate	93,747	(46,758)
Total obligations at end of period	**$ 187,007**	**$ 90,281**
Less current obligations at end of period	(5,419)	(7,003)
Long-term obligations at end of period	**$ 181,588**	**$ 83,278**

During 2022, we increased the asset retirement obligations related to two pits at the Colowyo Mine by $12.1 million due to revised cost estimates, with an offsetting decrease in the asset retirement obligation related to the third pit of $1.4 million due to reclamation costs paid and a gain on settlement. In the second quarter of 2022, we increased the environmental reclamation obligation at the New Horizon Mine by $44.9 million due to revised cost estimates. The New Horizon Mine environmental remediation liability is $67.3 million as of December 31, 2022. Of this amount, $36.8 million is recorded on a discounted basis, using a discount rate of 3.25 percent, with total estimated undiscounted future cash outflows of $57.9 million. Environmental obligation expense is included in other operating expenses on our consolidated statement of operations. Although the entire environmental obligation has been expensed, we may seek future rate recovery in upcoming rate filings with FERC. We continue to evaluate the New Horizon Mine and the Colowyo Mine post reclamation obligations and will make adjustments to these obligations as needed. Also, during 2022, we recorded an additional asset retirement obligation of $36.8 million related to a change in cost estimates for our pond, ash landfill and post-closure reclamation obligations at various generating stations.

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

NOTE 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, 2022 and December 31, 2021.

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 $0.8 million of this unearned revenue in 2022 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, 2022	December 31, 2021
Accounts receivable - Members	**$ 103,246**	**$ 95,630**
Other accounts receivable - trade:		
Non-member electric sales	17,213	5,684
Other	9,141	13,505
Total other accounts receivable - trade	**26,354**	**19,189**
Other accounts receivable - nontrade	6,082	2,382
Total other accounts receivable	**$ 32,436**	**$ 21,571**
Contract liabilities (unearned revenue)	**$ 5,123**	**$ 5,372**

NOTE 6 – LONG-TERM DEBT

We have $2.9 billion of long-term debt which consists of mortgage notes payable, pollution control revenue bonds and the Springerville certificates. The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement ("Master Indenture") except for one unsecured note in the aggregate amount of $4.1 million as of December 31, 2022. 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. A DSR below 1.025 under the Master Indenture would require us to transfer all cash to a special fund managed by the trustee of the Master Indenture.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC"), as lead arranger and administrative agent, in the amount of $520 million ("2022 Revolving Credit Agreement") that expires on April 25, 2027. We had no outstanding borrowings under the 2022 Revolving Credit Agreement as of December 31, 2022. As of December 31, 2022, we had $246 million in availability (including $226 million under the commercial paper back-up sublimit) under the 2022 Revolving Credit Agreement.

On October 3, 2022, we remarketed the Moffat County, CO pollution control revenue bonds on their mandatory tender date into a new 5-year term rate mode at 2.9 percent ending October 1, 2027.

On July 26, 2022, we completed a tender offer in an aggregate amount of $100 million of our First Mortgage Bonds, Series 2014E-1 (due 2024). We paid a total of $100.2 million in aggregate for the purchase of the bonds, including early tender payments. The transaction was funded using available cash and short-term borrowings.

Long-term debt, including applicable terms and interest rates as of December 31, 2022, consists of the following (dollars in thousands):

	December 31, 2022	December 31, 2021
Mortgage notes payable		
2.32% to 3.66% CFC, due through 2028	$ 85,855	$ 106,182
2.63% to 4.43% CoBank, ACB, due through 2042	174,985	204,163
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	228,783	250,000
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	128,002	244,714
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	250,000	250,000
First Mortgage Bonds, Series 2010A, 6.00% due 2040	499,805	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
Variable rate CFC, as determined by CFC, due through 2026	—	324
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	296,430	297,039
Pollution control revenue bonds		
Moffat County, CO, 2.90% term rate through October 2027, Series 2009, due 2036	46,800	46,800
Springerville certificates		
Series B, 7.14%, due through 2033	248,601	292,985
Total long-term debt	**$ 2,981,481**	**$ 3,214,427**
Less debt issuance costs	(21,481)	(23,110)
Less debt discounts	(8,960)	(9,398)
Plus debt premiums	11,843	12,990
Total debt adjusted for discounts, premiums and debt issuance costs	**$ 2,962,883**	**$ 3,194,909**
Less current maturities	(92,920)	(93,039)
Long-term debt	**$ 2,869,963**	**$ 3,101,870**

Annual maturities of total long-term debt adjusted for debt issuance costs, discounts and premiums at December 31, 2022 are as follows (dollars in thousands):

2023	$ 92,920
2024 (1)	223,835
2025	88,819
2026	90,440
2027	92,323
Thereafter	2,374,546
	$ 2,962,883

(1) Includes $128 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 2022 Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our 2022 Revolving Credit Agreement. The commercial paper issuances are used to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances vary but may not exceed 397 days from the date of issue. The commercial paper notes are classified as current and are included in current liabilities as short-term borrowings on our consolidated statements of financial position.

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

	2022	2021
Commercial paper outstanding, net of discounts	$ 274,102	$ 49,997
Weighted average interest rate	4.61 %	0.20 %

At December 31, 2022, $226 million of the commercial paper back-up sublimit remained available under the 2022 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, 2022		December 31, 2021	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 10,604	$ 9,808	$ 8,850	$ 8,640

Marketable Securities

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

	December 31, 2022		December 31, 2021	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 558	$ 489	$ 597	$ 598

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $101.8 million and $95.3 million as of December 31, 2022 and 2021, 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, 2022		December 31, 2021	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 2,981,481	$ 2,725,606	$ 3,214,427	$ 3,759,991

NOTE 9 – INCOME TAXES

We had no current income tax expenses or benefits in 2022 or 2021 after regulatory treatment. We had a deferred income tax benefit of $0.2 million in 2022 and deferred income tax expense of $0.3 million in 2021.

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. As a FERC jurisdictional entity, we recognize deferred income tax expense under the normalization method whereby 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, 2022	December 31, 2021
Deferred tax assets		
Net operating loss carryforwards	$ 165,636	$ 144,602
Operating lease liabilities	105,039	114,237
Deferred revenues and membership withdrawal	16,028	38,784
Safe harbor lease receivables	8,939	8,135
Other	43,795	30,578
	339,437	**336,336**
Less valuation allowance	—	—
	339,437	**336,336**
Deferred tax liabilities		
Basis differences- property, plant and equipment and other	166,568	159,696
Operating lease right-of-use assets	125,939	130,111
Capital credits from other associations	34,236	31,622
Deferred debt prepayment transaction costs	27,381	29,434
Other	4,588	4,460
	358,712	**355,323**
Net deferred tax liability	**$ (19,275)**	**$ (18,987)**

Net deferred tax liabilities increased by $0.3 million in 2022 which is deferred and reflected as an increase 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 $19.3 million and $18.7 million at December 31, 2022 and 2021, respectively.

The reconciliation between pretax GAAP income and deferred income tax expense (benefit) is as follows (dollars in thousands):

	2022	2021	2020
Pretax GAAP income at Federal statutory rate	$ —	$ 5,435	$ 5,271
Pretax GAAP income at State statutory rate, net of federal benefit	—	725	703
Patronage exclusion	—	(6,159)	(5,974)
Asset retirement and environmental reclamation obligations	16,655	10,917	(14,230)
Deferred revenues and membership withdrawal	(22,759)	18,673	(29,519)
Operating liabilities, net of right-of-use assets (1)	(4,919)	1,165	5,277
Valuation Allowance	—	—	(30,468)
Net operating loss carryforward	21,034	(27,539)	367
Other items, net	(9,445)	(2,531)	17,543
Impairment	—	—	20,554
Regulatory treatment of deferred taxes	(815)	(391)	29,942
Total deferred income tax expense (benefit)	**$ (249)**	**$ 295**	**$ (534)**

We had an estimated consolidated tax loss of $93.1 million for 2022. At December 31, 2022, we have an estimated consolidated federal net operating loss carryforward of $696.0 million of which pre-2018 tax years in the amount of $444.5 million are subject to expiration periods between 2031 and 2037 and $251.5 million have no expiration. We have $438.2 million of state net operating loss carryforwards, of which $405.1 million is subject to expiration periods between 2031 and 2041 and $33.1 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 deferred tax assets 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.

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

NOTE 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 $223.6 million, or 18.4 percent, of our Utility Member revenue and 14.7 percent of our total operating revenues in 2022. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues in 2022.

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):

	2022	2021	2020
Non-member electric sales:			
Long-term contracts	$ 56,570	$ 44,383	$ 46,172
Short-term contracts	106,785	70,525	44,210
Rate stabilization	95,613	78,457	12,136
Provision for rate refunds	(51)	(10,196)	—
Coal Sales	7,021	4,951	7,326
Other	54,399	51,390	46,219
Total non-member electric sales and other operating revenue	**$ 320,337**	**$ 239,510**	**$ 156,063**

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

Rate stabilization represents recognition of income from withdrawal of former Utility Members from membership in us or non-member electric sales revenue that was previously deferred in accordance with accounting requirements related to regulated operations. We recognized $95.6 million of deferred membership withdrawal income for the year ended December 31, 2022, and $78.5 million and $12.1 million of deferred non-member electric sales revenue for the years ended December 31, 2021 and December 31, 2020, respectively, as directed by our Board. See Note 2—Accounting for Rate Regulation.

Provision for Rate Refunds

Provision for rate refunds represents refund of certain revenues based on a FERC order. Based upon a FERC order requiring us to refund certain revenue from power sales in the Western Area Colorado Missouri ("WACM") balancing authority area, in the third quarter of 2022, we reserved $2.0 million as a preliminary estimate of the amount to be refunded. As required by FERC, in December 2022, we distributed refunds of $2.7 million. See Note 15 - Commitments and Contingencies - Legal. Such an amount was offset by the recognition of a favorable adjustment during the second quarter of 2022 of approximately $2.9 million for the amount in excess of an accrual that was previously recorded related to certain energy sales to third parties in excess of the soft-cap for short-term, spot market sales of $1,000 per megawatt hour established by the Western Electricity Coordinating Council. See Note 15 - Commitments and Contingencies- Legal.

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 $2.7 million in 2022 and $3.5 million in 2021. Rent expense is included in operating expenses on our consolidated statements of operations. As of December 31, 2022, 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, 2022	December 31, 2021
Operating leases		
Operating lease right-of-use assets	$ 8,784	$ 9,081
Less: Accumulated amortization	(2,013)	(1,552)
Net operating lease right-of-use assets	**$ 6,771**	**$ 7,529**
Operating lease liabilities – current	$ (441)	$ (491)
Operating lease liabilities – noncurrent	(1,251)	(1,622)
Total operating lease liabilities	**$ (1,692)**	**$ (2,113)**
Operating leases		
Weighted average remaining lease term (years)	7.6	7.6
Weighted average discount rate	3.87 %	3.79 %

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

Year 1	$ 386
Year 2	342
Year 3	151
Year 4	431
Year 5	94
Thereafter	549
Total lease payments	**$ 1,953**
Less imputed interest	(261)
Total	**$ 1,692**

Leasing Arrangements as Lessor

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $7.1 million in 2022 and $7.3 million in 2021 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 13—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 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,105 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan ("RS Plan") except for the 191 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 2022, 2021 and 2020 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 $25.2, $26.7 and $27.5 million in 2022, 2021 and 2020, 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, other plan experiences 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, 2022 and January 1, 2021, 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):

	2022	2021
Executive benefit restoration obligation at beginning of period	$ 9,852	$ 7,379
Service cost	468	440
Interest cost	300	205
Plan amendments - prior service cost	308	1,050
Curtailment	(292)	—
Benefit payments	(110)	—
Actuarial (gain) loss	(2,041)	778
Executive benefit restoration obligation at end of period	**$ 8,485**	**$ 9,852**
Fair value of plan assets at beginning of year	$ 8,640	$ 6,955
Employer contributions	1,734	1,762
Benefits paid	(109)	—
Actual return on plan assets	(457)	(77)
Fair value of plan assets at end of year	**$ 9,808**	**$ 8,640**
Net (asset) liability recognized	**$ (1,323)**	**$ 1,212**

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):

	2022		2021	
Accumulated other comprehensive loss at beginning of period	$	(4,932)	$	(4,873)
Plan amendments - prior service cost		(308)		(1,050)
Amortization of prior service cost into other income		1,156		1,113
Amortization of actuarial loss		426		515
Curtailment and settlement		(187)		141
Unrecognized actuarial gain (loss)		1,740		(778)
Accumulated other comprehensive loss at end of period	**$**	**(2,105)**	**$**	**(4,932)**

DEFINED CONTRIBUTION PLANS: 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 $3.9 million, $3.3 million, and $3.5 million in 2022, 2021, and 2020, respectively.

Effective January 1, 2022 we adopted a 409(a) non-qualified plan. Senior managers, vice presidents and executive officers hired prior to May 1, 2021 are eligible to participate and contribute to the plan, but are not eligible for any employer contribution. Executive officers hired on or after May 1, 2021 will be eligible to participate and contribute to the plan, and are eligible for the employer contribution. The employer contribution is effective once the eligible executive has reached the maximum allowed contribution and employer contribution and match in our base 401(k) plan and includes a maximum employer contribution of 10 percent which includes an employer base contribution and an employer match. We made minimal contributions to the plan in 2022.

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, 2022, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles. As of June 30, 2021, the plans ceased to provide postretirement medical benefits for employees who retire after June 30, 2021.

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

	2022		2021	
Postretirement medical benefit obligation at beginning of period	$	2,809	$	9,985
Interest cost		47		36
Benefit payments (net of contributions by participants)		(732)		(730)
Actuarial gain		(32)		(784)
Plan amendments		—		(5,698)
Postretirement medical benefit obligation at end of period	**$**	**2,092**	**$**	**2,809**
Postemployment medical benefit obligation at end of period		97		419
Total postretirement and postemployment medical obligations at end of period	**$**	**2,189**	**$**	**3,228**

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):

	2022		2021	
Amounts included in accumulated other comprehensive income at beginning of period	$	3,580	$	(841)
Amortization of prior service credit into other income		(1,636)		(2,139)
Amortization of actuarial loss into other income		102		78
Actuarial gain		32		784
Plan amendments		—		5,698
Amounts included in accumulated other comprehensive income at end of period	**$**	**2,078**	**$**	**3,580**

The assumptions used in the 2022 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	1.82 %
Initial health care cost trend (2018)	7.00 %
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)	2.99

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):

2023	$ 576,432
2024	482,090
2025	379,064
2026	298,176
2027	200,190
2028 through 2032	362,795
	$ 2,298,747

NOTE 13 – VARIABLE INTEREST ENTITIES

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

Consolidated Variable Interest Entity

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

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

	December 31, 2022	December 31, 2021
Net electric plant	$ 721,997	$ 740,135
Noncontrolling interest	126,180	119,101
Long-term debt	254,876	300,220
Accrued interest	7,400	8,721

Our consolidated statements of operations include the following Springerville Partnership expenses (dollars in thousands):

	Twelve Months Ended		
	2022	2021	2020
Depreciation, amortization and depletion	$ 18,138	$ 18,138	$ 18,138
Interest	17,064	20,038	22,798

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.

NOTE 14 – 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, 2022, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2023	$	30,627
2024		23,217
2025		10,113
2026		6,882
2027		6,825
Thereafter		88,247
	$	**165,911**

Our coal purchases were $124.0 million in 2022, $97.9 million in 2021, and $101.2 million in 2020.

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, 2022, 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 were as follows (dollars in thousands):

	2022		2021		2020	
Basin	$	148,146	$	146,532	$	152,461
WAPA		67,791		70,107		72,491
Renewables, other than WAPA		85,601		71,565		69,255

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 ("FPA") and that FERC's jurisdiction preempts the jurisdiction of the Colorado Public Utilities Commission ("COPUC") to address any rate related issues, including the complaints filed by United Power and La Plata Electric Association ("LPEA") with the COPUC.

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

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

Petitions for review related to our tariff filings, including our Utility Member rates, have been filed with the D.C. Circuit Court of Appeals by other parties. On December 29, 2022, an order was issued by the court to hold all the cases before the D.C. Circuit Court of Appeals in abeyance, directing the parties to file motions to govern future proceedings by March 29, 2023.

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

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

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

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

On October 22, 2020, the COPUC determined that COPUC's jurisdiction over United Power and LPEA's complaints was preempted by FERC 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. On November 3, 2022, United Power filed a motion to dismiss the appeal with prejudice that was granted by the court on November 23, 2022.

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

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

On April 6, 2022, we and each Non-Utility Member filed their respective answers to the first amended complaint denying that United Power is entitled to any relief and requesting the court enter judgment of dismissal. We are also requesting declaratory judgements that the April 2019 Bylaws amendment and the April 2020 Board approvals related to the methodology to calculate a contract termination payment and buy-down payment formula are valid. On April 27, 2022, United Power filed a reply asserting that we are not entitled to any relief on our requests for declaratory judgement. A jury trial is scheduled for June 2023. In United Power's February 2023 expert report, United Power asserts that its damages are in the range of $483 million to $533 million, plus interest after the date of the expert report. It is not possible to predict the outcome of this matter, whether we will incur any liability in connection with this matter, and in the event of liability, if any, the amount of damages that could be awarded.

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

On April 29, 2022, we filed a response to the show cause order. FERC issued a decision on September 22, 2022 that revoked our market-based rate authorization in the WACM balancing authority area. Such revocation means that we cannot sell power in the WACM balancing authority area to non-members at bilaterally negotiated "market-based" rates. The FERC order instead required us to file, within 30 days of the order, a tariff for cost-based rates applicable to non-member sales in the WACM balancing authority area that would otherwise have been made under our market-based rate tariff. The order further required us to refund any revenue from power sales in the WACM balancing authority area to non-members on or after March 7, 2022 in excess of the cost-based rates, and submit a refund report within 30 days of the order. On October 7, 2022, FERC granted our motion to extend the deadline until December 21, 2022 to make the above referenced filings. As required by FERC, in December 2022, we distributed refunds with applicable interest of $2.7 million. On December 14, 2022, we also filed a cost-based rate tariff with FERC for our sales in the WACM balancing authority area, and such cost-based rate tariff was used to calculate the amount refunded. On February 27, 2023, FERC accepted our cost-based rate tariff.

Energy Sales - Soft-Cap. In August 2020, we made certain energy sales to third parties in excess of the soft-cap price for short-term, spot market sales of $1,000 per megawatt hour established by the Western Electricity Coordinating Council. On October 7, 2020, we filed a report with FERC justifying the sales above the soft-cap and we did not recognize the revenue for the energy sales in excess of the soft-cap, EL21-65-000. Based upon additional guidance from FERC, we filed a supplemental report on July 19, 2021. On May 20, 2022, FERC issued an order directing us to refund only certain amounts of the energy sales revenue in excess of the soft-cap. Based upon the FERC order, in the second quarter of 2022, we recognized approximately $2.9 million in excess of the soft-cap and refunded $0.4 million to a third party. On July 22, 2022, the California Public Utilities Commission filed a petition for review with the DC Circuit Court of Appeals of FERC's May 20, 2022 order, 22-1169. On August 18, 2022, we filed a motion to intervene with the DC Circuit Court of Appeals and an order granting said motion was issued on September 6, 2022. On January 24, 2023, the parties to the proceeding filed a motion with the court to consolidate this proceeding with other related proceedings with the DC Circuit Court of Appeals and proposed a procedural schedule with final briefings due in October 2023. On March 6, 2023, the DC Circuit Court of Appeals granted the motion to consolidate the proceedings. It is not possible to predict the outcome of this matter or whether we will be required to refund any additional amounts to third parties.

NOTE 15 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 10, 2023, which is the date when the financial statements were issued.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this annual report, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that as of December 31, 2022 our disclosure controls and procedures were not effective due to a material weakness in internal control over financial reporting as described below.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and Board; and
- provide reasonable assurance that unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements are prevented or detected timely.

Management, including our principal executive officer and principal financial officer, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013. Based on the COSO criteria, control deficiencies that constitute a material weakness were identified. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is more than a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness was identified:

During the quarter ending December 31, 2022, a material weakness in our controls related to the accounting for asset retirement and environmental reclamation obligations for coal mines was identified. This material weakness did not, however, result in a misstatement to the reported consolidated financial statements, and notwithstanding the material weakness, management, including our chief executive officer and chief financial officer, believes the consolidated financial statements included in this Form 10-K fairly represent, in all material respects, our financial condition, results of operations and cash flows at and for the periods presented in accordance with GAAP.

Remediation

With these issues identified, we have evaluated and have begun implementing the following remediation action steps to ensure that the control deficiencies contributing to the material weakness are remediated:

- Establish separate accounts for each mine pit in order to segregate each related asset retirement obligation into its own individual account.
- Establish procedures to perform monthly rollforward schedules for each asset retirement and environmental reclamation obligation and utilize those rollforward schedules in the monthly account reconciliation process to identify issues on a more timely basis.
- Establish a calculation model which will only be used for a mine pit in final reclamation in order to more accurately adjust the remaining obligation.
- Implement quarterly meetings between management and staff in order to review both the asset retirement and environmental reclamation obligations.
- Engage with third party consultants to evaluate our current processes.

Changes in Internal Control over Financial Reporting

Other than those described above, there were no changes that occurred during the fourth quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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