TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
2015 ANNUAL REPORT

ONE FAMILY POWERED BY MANY.

WE BELIEVE

AFFORDABLE AND RELIABLE POWER, RESPONSIBLY GENERATED AND DELIVERED, IS THE LIFEBLOOD OF THE RURAL WEST. THE FARMS, RANCHES, SMALL TOWNS AND RESORTS THAT OUR MEMBERS SERVE ARE CLOSELY TIED TO THE LANDSCAPE AND THEIR POWER SUPPLY.

WE UNDERSTAND

THE RESPONSIBILITIES THAT COME WITH SERVING OUR 44 MEMBER ELECTRIC DISTRIBUTION COOPERATIVES AND PUBLIC POWER DISTRICTS THAT COLLECTIVELY DELIVER ELECTRICITY TO 1.5 MILLION CONSUMERS.

OUR STRENGTH

COMES FROM THE GEOGRAPHIC AND ECONOMIC DIVERSITY OF OUR MEMBERS, THE BENEFITS OF THE COOPERATIVE BUSINESS MODEL AND INNOVATIVE THINKING THAT BRINGS THE BEST UTILITY PRACTICES TO RURAL COMMUNITIES AND INDUSTRIES.

BY THE NUMBERS

TRI-STATE IN 2015

TRI-STATE'S OPERATIONAL AND FINANCIAL STRENGTHS PLACE US AMONG THE HIGHEST PERFORMERS IN THE GENERATION AND TRANSMISSION INDUSTRY.

FINANCIALS

$1.3 B
Operating Revenue

$53.4 M
Net Margin

$4.8 B
Total Assets

ENERGY SALES

15.8 GWh
Member Sales

2 GWh
Non-Member Sales

17.8 GWh
Total Energy Sales

QUICK FACTS

12.0 GWh
Power Produced in 2015

7.1¢ / kWh
Average Member Wholesale Rate

1,561
Employees, Including Subsidiaries

5,558
Miles of Transmission Lines

NET MARGIN

Millions of Dollars

2013	72.9
2014	64.2
2015	53.4

POWER PRODUCED

Gigawatt Hours

2013	12.5
2014	12.4
2015	12.0

TOTAL SALES

Gigawatt Hours

2013	18.6
2014	18.7
2015	17.8

MEMBER COINCIDENT PEAK DEMAND

Megawatts

2013	2,666
2014	2,813
2015	2,753

SOURCES OF GENERATION

1,874 MW
Coal

897 MW
Natural Gas/Oil

923 MW
Renewables

558 MW
Contracts

FROM THE CHAIRMAN

Throughout 2015, our association focused its energy to address and resolve several significant matters within the membership. We respectfully approached this hard work within our cooperative family by adhering to our cooperative values. With robust communication and effective processes, we strongly positioned our association for the future.

Our membership and, ultimately, our board of directors addressed the association's wholesale power contracts and rate design. These two matters are fundamentally important to how our members relate to one another in our association, and addressing these issues provides us greater certainty going forward.

Early in 2015, our membership concluded its review of our wholesale power contracts. The association regularly reviews these contracts to ensure alignment with the needs and interests of both the membership and the association as a whole.

A contract committee, including member system directors, member system CEOs and Tri-State directors, worked for months to review the association's wholesale power contract with the membership. Tri-State's board of directors accepted the committee's recommendation not to make changes to the contract.

Tri-State aggressively develops cost effective, utility-scale renewable resources, and we recognize some members seek to develop renewable generation at the local level. Within our contracts, our renewable energy policies are responsive to our members' desires, ensuring each individual member's renewable energy goals can be realized, while protecting all members' interest in the association.

The membership also reviewed and revised the association's wholesale rate structure. A rate committee, led by the membership and consisting of member system directors, member system CEOs and Tri-State directors, performed this challenging and complex work. A member-directed, third-party cost-of-service study supported the committee's unanimous recommendation for a significant change in the association's wholesale rate structure.

The board unanimously adopted the committee's rate design recommendation, which became effective Jan. 1, 2016. With the new rate structure, we anticipate that state regulatory processes related to the previous rate design will move towards resolution in 2016.

Tri-State's sound financial performance allowed our board to declare a $10 million patronage capital refund to our membership. This refund is a hallmark of our cooperative system and demonstrates the value of cooperative membership.

I want to thank the membership, our board of directors and Tri-State staff for their work in 2015. We approached our work together grounded in our cooperative principles and focused on members' needs. Together, we strengthened our cooperative family for the possibilities of 2016.

RICK GORDON

At Tri-State, we understand the value that affordable and reliable power, responsibly generated, brings to the rural West. In 2015, Tri-State continued to serve our mission for our 44 member systems – our cooperative family – with wise guidance from our board of directors, the engagement of our member systems and the dedication of our employees.

Fundamental to our shared success is the continued revitalization of the relationships we have with our members. The association has continued to nurture its member communications and relations, which has helped resolve several longstanding matters. Effective membership committees, active member advisory councils and vigorous member orientation programs have empowered us to better understand and work alongside our members.

With unanimous approval by our board of directors in 2015, our association will have a new, more traditional wholesale rate design in place in 2016. Tri-State also worked to control costs in 2015, resulting in no increase in the average wholesale rate for 2016.

Michael S. McInnes

MIKE McINNES

FROM THE CEO

Our safety record remained better than the national average, and we maintained compliance with stringent security, safety, environmental and reliability requirements.

Alongside 27 states, fellow cooperatives and industry associations, Tri-State took an active role in challenging the Environmental Protection Agency's Clean Power Plan, which we believe is unworkable and unenforceable. We have dedicated a multidisciplinary team of our experienced staff to organize our efforts to address the rule, even as we continue to proactively address carbon emissions through plant efficiency improvements, renewable energy development, research and development, and support of energy efficiency programs with our members.

Tri-State continues to develop renewable energy resources, and construction was completed on the association's largest project, the 150-megawatt Carousel Wind Farm. Also in 2015, Tri-State announced two new utility-scale solar projects will be completed in 2016 and a new wind project will be completed in 2017.

Following our successful refinancing of $1.6 billion of our debt in 2014, Tri-State went through the Securities and Exchange Commission registration process and registered $500 million of securities in 2015. Tri-State is well positioned to access cost effective, flexible debt capital in the future. At the end of 2016, Tri-State will fall under the requirements of the Sarbanes-Oxley Act and we continue to work towards compliance. Our transparency, business controls, accountability and process consistency will continue to improve as part of this effort.

Operationally, Tri-State's assets continue to perform well for our cooperative family. To maintain the reliability and compliance of our generation fleet, Craig Station received control upgrades and work continued on new emissions control systems. Joining the Southwest Power Pool for our eastern interconnect facilities reduced transmission costs, and nine new member delivery points were completed, along with modifications to nine other member delivery points.

With great resolve from our elected officials, the communities of northwest Colorado, federal officials and Tri-State staff, an environmental review of Colowyo Mine was successfully completed in 120 days. We are grateful for the support that protected a vital fuel supply for Craig Station and the livelihoods of more than 220 mine employees and their families.

As we go forward, we will remain vigilant in our mission: controlling costs, engaging with our members and connecting the best utility practices to the vast reaches of the West.

POLICY AND COMPLIANCE Q&A

BARBARA WALZ, SVP POLICY & COMPLIANCE, CCO

Electric utilities are among the most regulated industries in the nation. Each year brings new legislative and regulatory proposals and environmental rules garner significant attention. Tri-State is also responsible for complying with accounting, safety, labor, reliability and a host of other regulations. As the Senior Vice President of Policy and Compliance and Chief Compliance Officer, Barbara Walz is responsible for many aspects of Tri-State's regulatory performance.

Q: What is the primary goal of Tri-State's compliance programs?

A: Tri-State's compliance programs focus on managing liabilities and meeting federal, state and local requirements while minimizing risks to the association and our members. Once there is a legislative or regulatory requirement, we implement it as efficiently as is possible. The plethora of new regulations proposed and implemented each year also requires the development and improvement of processes and programs to ensure 100 percent compliance and cost-effective operation of Tri-State's generation and transmission fleet.

Q: How do regulations impact Tri-State?

A: From 2005 through 2014, federal agencies published more than 35,000 final rules in the Federal Register. As the magnitude and complexity of regulations increase, so do compliance costs and resource demands. New regulations can require updates to operations, installation of new equipment or the addition of staff to analyze, monitor and report on compliance. For example, the Environmental Protection Agency's Clean Power Plan is more than 2,000 pages and its implementation would significantly change how the electric industry operates. In response, Tri-State has dedicated significant staff and resources to review, analyze and challenge the rule.

Q: What steps have been taken to reduce the cost burden of regulation?

A: Tri-State continues to be a strong, proactive steward of our resources and was the first G&T to put into place an environmental management system. The Tri-State board of directors has a long-standing strategic goal to mitigate the impacts of legislation and regulation and manage compliance costs. We believe rules should be reasonable, based on the law and sound science, and not cause significant cost increases to our members. We review new proposals and work with regulators and elected officials to address negative impacts without commensurate benefits. We actively engage in regulations that affect our operations, such as the Maximum Achievable Control Technology rules, and work on issues including the Endangered Species Act and the Waters of the United States. Once regulations are in place, our focus turns to complying in the most cost-effective manner possible, working to ensure fair reporting requirements and addressing overreaching regulatory interpretations.

ENERGY MANAGEMENT Q&A

BRAD NEBERGALL, SVP ENERGY MANAGEMENT

In an increasingly complex and competitive energy market, it's more important than ever for Tri-State to schedule and dispatch our generation, transmission and contracted resources, including variable resources, in the most optimized and efficient manner possible. Brad Nebergall serves as Senior Vice President of Energy Management and leads the teams that ensure Tri-State best utilizes its expanding base of resources that have a significant impact on the association's bottom line.

Q: What are Energy Management's primary responsibilities and value to our members?

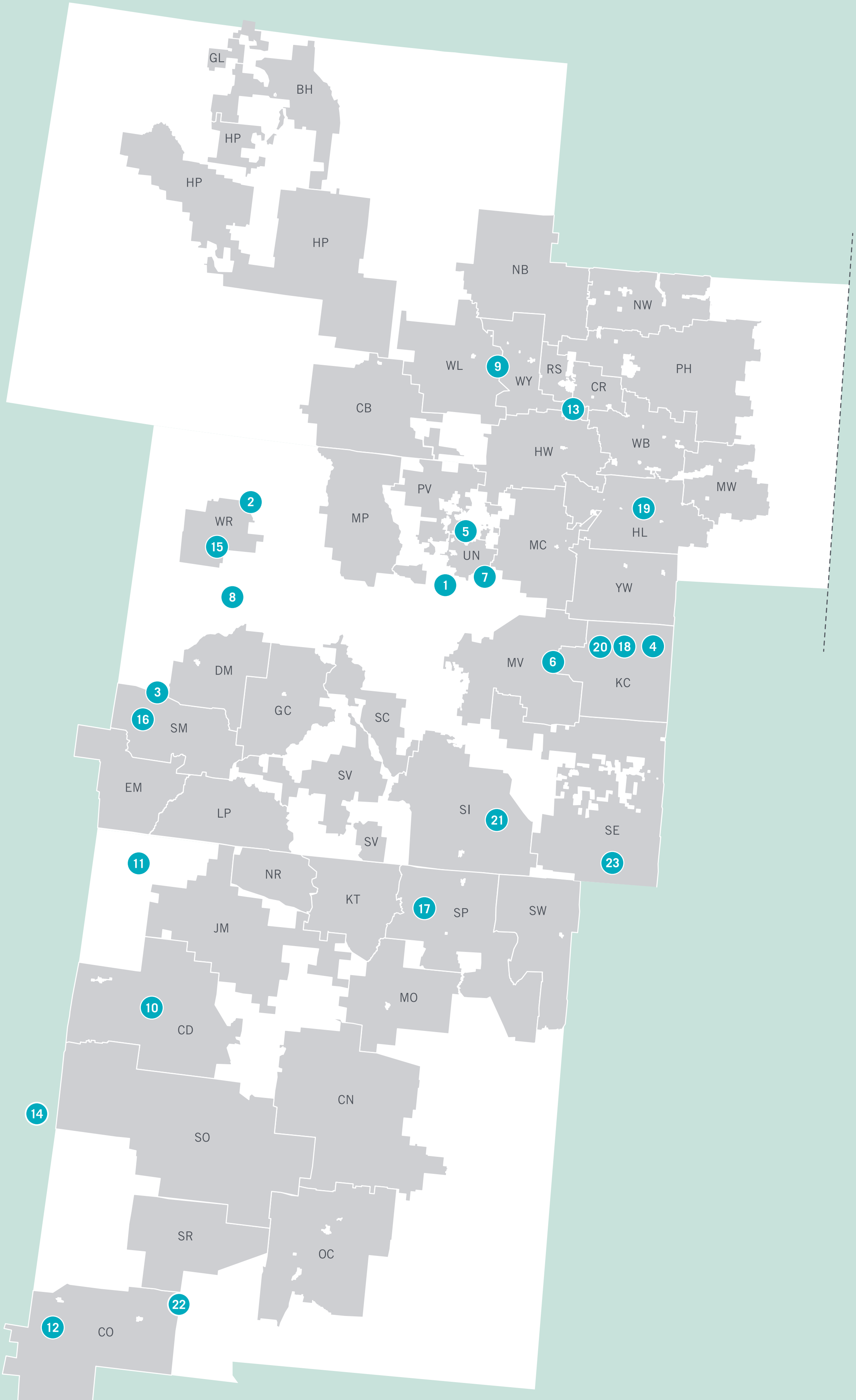
A: We have a significant role in the operations of Tri-State, including resource dispatch, power marketing and trading, resource planning, load forecasting, risk management and third-party transmission. The energy markets and resource dispatch group's impact is immediate as they determine the optimal mix of more than 30 different generation resources every minute of every day. The resource planning process results in recommendations to the board of directors on our future generation mix, which impacts the association for decades. Since our latest coal plant came online in 2006, Tri-State has added over 1,000 megawatts of natural gas and renewable generation through acquisitions and cost effective power purchase agreements.

Q: With nearly a quarter of the energy Tri-State members sell being renewable, do you see more renewables in the future?

A: The Tri-State board approved five new renewable resources that will be coming online in the next two years. These include the Carousel (150 MW), Twin Buttes II (76 MW) and Colorado Highlands (4 MW) wind projects, and the San Isabel (30 MW) and Alta Luna (25 MW) solar projects. These projects have a cost benefit to the membership and help reduce emissions. We will continue to seek projects that deliver these benefits.

Q: How have the big changes in energy prices impacted Tri-State?

A: With volatility in the oil and gas markets, Tri-State is impacted in both directions. When energy commodity prices are high, we see new load growth on our members' systems from the oil and gas industry, but we also have to pay more for the natural gas we use in our intermediate and peaking power generation units. Likewise, when prices are low, we see lower activity from the industry but our fuel costs are lower and we utilize more natural gas. Overall, Tri-State is well hedged and we are largely insulated from wild commodity price fluctuations.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CO

OUR MEMBERS

COLORADO

DM Delta-Montrose Electric Association, *Montrose*
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 The 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*
KT Kit Carson Electric Cooperative, Inc, *Taos*
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*

OUR RESOURCES

1. Headquarters and Operations Center
Westminster, Colorado
2. Craig Station
Craig, Colorado
3. Nucla Station
Nucla, Colorado
4. Burlington Station
Burlington, Colorado
5. J.M. Shafer Generating Station
Fort Lupton, Colorado
6. Limon Generating Station
Limon, Colorado
7. Frank R. Knutson Generating Station
Brighton, Colorado
8. Rifle Generating Station
Rifle, Colorado
9. Laramie River Station
Wheatland, Wyoming
10. Escalante Generating Station
Prewitt, New Mexico
11. San Juan Generating Station
Farmington, New Mexico
12. Pyramid Generating Station
Lordsburg, New Mexico
13. David A. Hamil DC Tie
Stegall, Nebraska
14. Springerville Generating Station
Springerville, Arizona
15. Colowyo Mine
Meeker, Colorado
16. New Horizon Mine
Nucla, Colorado
17. Cimarron Solar Facility
Springer, New Mexico
18. Kit Carson Windpower
Burlington, Colorado
19. Colorado Highlands Wind
Fleming, Colorado
20. Carousel Wind (2016)
Burlington, Colorado
21. San Isabel Solar (2016)
Trinidad, Colorado
22. Alta Luna Solar (2016)
Luna County, New Mexico
23. Twin Buttes II Wind (2017)
Lamar, Colorado

THE YEAR IN REVIEW

2015 AT TRI-STATE G&T

What makes generation and transmission cooperatives unique among electric utilities is that we are member-owned and governed, and operate on a not-for-profit basis. We are different than investor-owned utilities in that our interests are not driven by shareholders, but by those we serve.

We remain focused on ensuring the association remains financially healthy with an emphasis on controlling costs. For many of our members, the cost of power makes up 70 percent or more of their total cost structure, so attention to cost is critical to their well-being.

Tri-State enters 2016 with no increase in our wholesale rate and with a strong financial position. The association's board of directors in 2015 approved a $10 million capital credit refund, which is a hallmark of the cooperative business model.

In 2015, the association completed two significant efforts, addressing both our wholesale power contracts and rate design. A contract committee, representing all members of the association, completed its review of Tri-State's wholesale power contract, resulting in a recommendation, adopted by the board of directors, to not change the contract at this time.

Another membership committee reviewed Tri-State's rate design, working with a third-party consultant to complete a cost-of-service study, evaluate rate design options and make recommendations for the association's future wholesale rate structure. The committee unanimously recommended a new rate design that the board of directors, also unanimously, approved. The decision returns the association to a more traditional rate design in 2016.

Fundamental to our mission to serve our members across a vast service area is how we own our resources and physically connect to loads, resources and markets. By owning a significant portion of the transmission system we utilize, we are able to quickly respond to the needs of our member systems, and in short time put new facilities and delivery points into service. In 2015, we completed nine new and modified nine additional member delivery points. Tri-State also reduced transmission costs by joining the Southwest Power Pool for our eastern interconnect transmission facilities in 2015.

IN 2015, THE ASSOCIATION COMPLETED TWO SIGNIFICANT EFFORTS, ADDRESSING BOTH OUR WHOLESALE POWER CONTRACTS AND RATE DESIGN.

How we generate and purchase power is as important to our members as the transmission lines that deliver electricity. Tri-State is able to meet our members' needs through owned-generation resources, long-term power purchase contracts and market purchases. Our diverse generation portfolio leverages the West's plentiful natural resources and helps us to manage risks and costs as we generate reliable and affordable electricity for our membership. In 2015, Tri-State completed a major outage at Craig Station Unit 3, including the installation of a distributed control system. In the fall of 2015, a planned outage was completed at J.M. Shafer Station, with a control system installation and a steam turbine overhaul to ensure the continued long-term reliability of the power plant.

To manage the costs of fuel supply, we utilize coal from Tri-State-owned mines and contract for other coal supplies through our cooperative network. In 2015, the U.S. Department of the Interior approved a modified mine plan for our Colowyo Mine, which was subject to a federal district court order requiring the federal government to update its environmental review of the mine. Colowyo Mine operates in full compliance with all federal and state environmental requirements and has been recognized with numerous awards for its environmental and reclamation efforts and successes.

Since its inception, Tri-State has utilized renewable energy through the federal hydropower system, and as costs for other renewable resources have decreased, Tri-State has added wind, solar and additional hydropower resources to our portfolio.

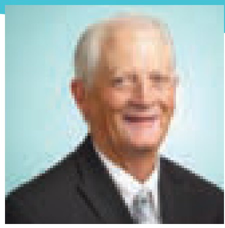
In 2015, approximately 23 percent of the energy Tri-State and our member systems delivered to cooperative members was generated from renewable resources, making the association one of the leading utilities in the country for using renewable power. Tri-State also provides incentives and technical support to its members' development of local renewable energy and distributed energy resources. Collectively, these member projects, completed or under development, account for approximately 79 megawatts of renewable energy resources. Tri-State's board approved new wind and solar resources totaling 285 megawatts that will become available in the next two years. These resources help reduce costs and emissions.

Environmental regulations continue to put pressure on the association's costs. In 2015, Tri-State, fellow electric cooperatives and industry associations, alongside 27 states, took an active role in challenging the Environmental Protection Agency's Clean Power Plan. Even as we challenged the federal rule, Tri-State worked with state officials as they began the development of their required compliance plans. There are many factors to consider before the impact on Tri-State and our members can be fully understood. Each state will take different approaches to comply with the rule, which challenges multi-state utilities like Tri-State to identify the clearest lowest-cost path to compliance.

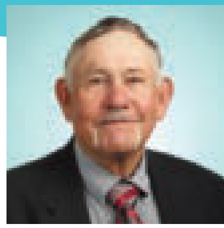
The association bolstered member communication and engagement through several efforts. Tri-State has three active member advisory councils to address demand response and energy shaping, distributed generation and renewable energy, and communications. The association also continued to educate and engage members through board and executive orientation sessions. A new, member-focused phase of the Power Makes It Possible marketing campaign was launched with many of the association's members to market their products and the value of electricity.

Tri-State remains committed to the communities we serve. In addition to supporting our communities through employee giving programs, as a Touchstone Energy Cooperative, we partner with our member systems in support of many other worthwhile causes across all four states we serve.

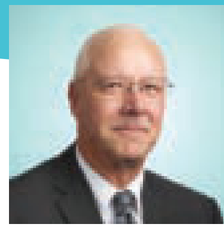
With our commitment to the cooperative business model and to serving our member systems, Tri-State stands apart from other utilities. Our top priority is and always will be providing reliable, affordable and responsible power to our members and the people and industries they serve. That's the cooperative difference.



Rick Gordon
Chairman
Mountain View Electric



Tony Casados, Jr.
Vice Chairman
Northern Rio Arriba Electric



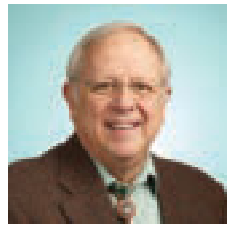
Leo Brekel
Secretary
Highline Electric

Stuart Morgan
Treasurer
Wheat Belt Public Power

Matt Brown
Assistant Secretary
High Plains Power

Julie Kilty
Assistant Secretary
Wyrulec Company

Joseph Herrera
Executive Committee
Socorro Electric



William Mollenkopf
Executive Committee
Empire Electric

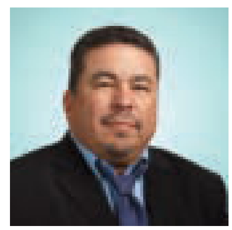
Joe Wheeling
Executive Committee
La Plata Electric

Robert Bledsoe
K.C. Electric

Jerry Burnett
High West Energy

Richard Clifton
Carbon Power & Light

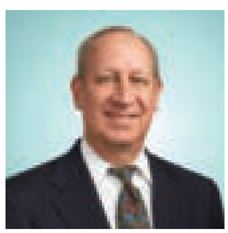
Wayne Connell
Central New Mexico Electric



Lucas Cordova, Jr.
Jemez Mountains Electric

Jack Finnerty
Wheatland Rural Electric

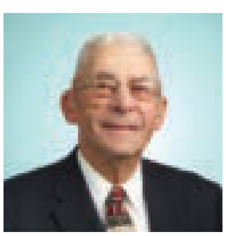
Gary Fuchser
Northwest Rural Public Power



John Gavan
Delta-Montrose Electric

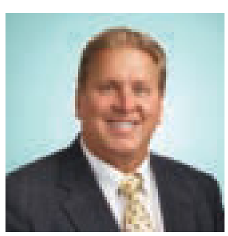
Jack Hammond
Niobrara Electric

Ron Hilkey
White River Electric

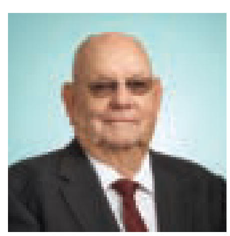


Ralph Hilyard
Roosevelt Public Power

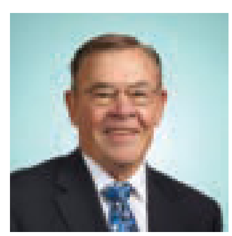
Don Kaufman
Sangre de Cristo Electric



Don Keairns
San Isabel Electric



Hal Keeler
Columbus Electric



Thaine Michie
Poudre Valley Rural Electric

THE BOARD OF DIRECTORS

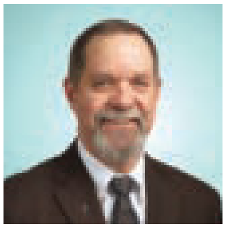
IN 2015

Virginia Mondragon
Mora-San Miguel Electric

Chris Morgan
Gunnison County Electric

Richard Newman
United Power

Stan Propp
Chimney Rock Public Power



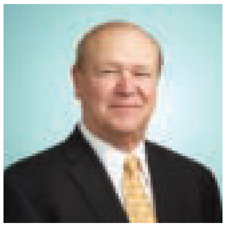
Tim Rabon
Otero County Electric

Gary Rinker
Southwestern Electric

Arthur Rodarte
Kit Carson Electric

Claudio Romero
Continental Divide Electric

Don Russell
Big Horn Rural Electric

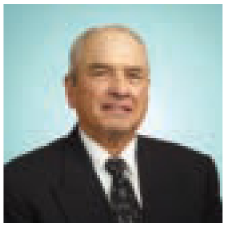


Brian Schlagel
Morgan County Rural Electric

Don Schutz
Springer Electric

Jack Sibold
San Miguel Power

Jim Soehner
Y-W Electric

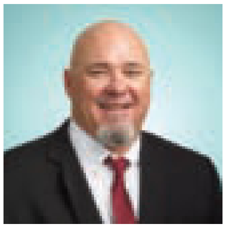


Darryl Sullivan
Sierra Electric

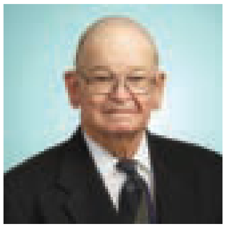
Jerry Thompson
Garland Light & Power

Carl Trick, II
Mountain Parks Electric

Shawn Turner
The Midwest Electric Cooperative



Scott Wolfe
San Luis Valley Rural Electric



Bill Wright
Southeast Colorado Power

Phil Zochol
Panhandle Rural Electric

EXECUTIVE MANAGEMENT TEAM

THE TEAM, FROM LEFT TO RIGHT: **Pat Bridges,** *Senior Vice President, Chief Financial Officer;* **Ellen Connor,** *Senior Vice President, Organizational Services, Chief Technology Officer;* **Jennifer Goss,** *Senior Vice President, Member Relations;* **Barry Ingold,** *Senior Vice President, Generation;* **Mike McInnes,** *Chief Executive Officer;* **Joel Bladow,** *Senior Vice President, Transmission;* **Barbara Walz,** *Senior Vice President, Policy and Compliance, Chief Compliance Officer;* **Brad Nebergall,** *Senior Vice President, Energy Management;* **Ken Reif,** *Senior Vice President, General Counsel*

WE BELIEVE IN

THE COOPERATIVE DIFFERENCE.

With our commitment to the cooperative business model and to serving our member systems, Tri-State stands apart from other utilities. Our top priority is and always will be providing reliable, affordable and responsible power to our members and the people they serve. That's the cooperative difference. As a testament to this, we asked a member CEO from each state we serve to share their thoughts about the benefits of being part of Tri-State.

WHEAT BELT PUBLIC POWER

SOUTHWEST NEBRASKA // TIM LINDAHL, CEO

EMPLOYEES: 27 **METERS:** 5,000 **SERVICE AREA:** 3,600 SQUARE MILES
FACILITIES: SIDNEY, HEADQUARTERS; DALTON & OSHKOSH, WAREHOUSE
LOAD SERVED: 34% IRRIGATION; 33% COMMERCIAL/INDUSTRIAL; 33% RESIDENTIAL

Tim Lindahl's ready smile radiates his confident conviction that Wheat Belt Public Power benefits from its Tri-State family. Originally from rural Colorado, Tim started at Wheat Belt in 2005 as an Information Technology Specialist. Three years later, he became the CEO of Wheat Belt.

COMPLIANCE EXPERTISE GROUNDED IN COMMITMENT TO MEMBERS

Some complex issues require significant subject matter expertise, training and education such as mitigating regulatory changes and their impacts. When Wheat Belt faced challenges brought on by North American Electric Reliability Corporation (NERC) compliance requirements, they turned to Tri-State.

"The help from Tri-State and its staff provided significant value to us in managing and ultimately removing the challenges," Tim said. After working through the compliance challenges together, Tri-State helped Wheat Belt and other members de-register their high-voltage assets. Tri-State then purchased the assets from Wheat Belt through an innovative board policy.

"When they purchased our transmission assets, that we were not as well equipped to manage, Tri-State helped us mitigate our cost and regulatory risk substantially," Tim said.

EDUCATION RESOURCES NURTURE STAFF AND LEADERSHIP

Tim appreciates Tri-State's education resources, which strengthen his team and board's performance. "We used Tri-State's orientation programs for our board and the association's member relations programs. I value the education my team and I can access on heavy-hitting subjects related to our industry. Better informed people make better decisions," he said.

Tri-State's introduction of member advisory councils has given Tim and his team more settings where they can learn from other members and Tri-State staff. Tim also appreciates the additional opportunities to contribute information to Tri-State's decision making process through the councils.

“WE USED TRI-STATE’S BOARD ORIENTATION PROGRAM FOR OUR BOARD AND THE ASSOCIATION’S MEMBER RELATIONS PROGRAMS. I VALUE THE EDUCATION MY TEAM AND I CAN ACCESS ON HEAVY-HITTING SUBJECTS RELATED TO OUR INDUSTRY. BETTER INFORMED PEOPLE MAKE BETTER DECISIONS.”

“THE RATE COMMITTEE IS A GOOD EXAMPLE OF ENGAGING THE MEMBERS IN THE SOLUTION. THIS LEVEL OF ENGAGEMENT IS KEY TO OUR SHARED SUCCESS.”

UNITED POWER

NORTH CENTRAL COLORADO // RON ASCHE, CEO

EMPLOYEES: 176 **METERS:** 77,000 **SERVICE AREA:** 900 SQUARE MILES
FACILITIES: BRIGHTON, HEADQUARTERS; FORT LUPTON & GOLDEN, OFFICES
LOAD SERVED: 57% INDUSTRIAL/COMMERCIAL; 40% RESIDENTIAL; 3% OTHER

Ron Asche brings his collaborative, forward thinking approach to our association alongside his commanding experience. Ron has logged 40 years in the electric utility industry: 35 years at Nebraska Public Power District with five years as CEO before retiring in 2011. Five years ago, he became the CEO of United Power. In May 2016, Ron will retire a second time.

RATE STRUCTURE SOLUTION EMBODIES EVOLUTION

When Tri-State's board formed a rate committee of the membership to address the association's rate structure, Ron was asked to chair the committee. He counts the committee as a stellar example of the collaborative cooperative spirit.

"Given the diversity of Tri-State members in size, loads and load factors, it can be difficult to establish a rate structure that is fair and equitable across the entire membership. So we focused on getting Tri-State members back together again," Ron said. "Our interest was on the association, rather than the individual co-op."

In just nine months, the committee and, in turn, the board, unanimously approved the new rate structure. "The rate committee is a good example of engaging the members in the solution," Ron said. "This level of engagement is key to our shared success."

KEEPING UP WITH DEMAND, REMAINING RELIABLE

United Power also values Tri-State's ability to keep up with its members' growth while maintaining reliability. In 2015, United Power experienced a 20 percent increase in energy sales over 2014. Tri-State and United have collaborated on several significant transmission projects to serve the cooperative's growing loads. "Keeping up with growth can be a challenge. Tri-State has done an exceptional job in supporting United Power in meeting our members' needs and expectations," Ron said.

WHEATLAND RURAL ELECTRIC

SOUTHEAST WYOMING // DON SMITH, GENERAL MANAGER

EMPLOYEES: 19 **METERS:** 4,000 **SERVICE AREA:** 4,406 SQUARE MILES
FACILITIES: WHEATLAND, HEADQUARTERS
LOAD SERVED: 12% IRRIGATION; 62% COMMERCIAL; 26% RESIDENTIAL

Don Smith gets to the heart of a conversation with quite a bit of energy and efficiency. Don has been the General Manager at Wheatland Rural Electric for two years. Prior to that, Don worked at Oregon People's Utility District for two years, at Alaska's Homer Electric for five years and the City of Gillette, Wyoming, for 16 years.

RECAPTURING THE CO-OP SPIRIT WITH COMMUNICATION

"I like the co-op lifestyle. I like the co-op business model," he said. "I like the trust Tri-State has in its members."

"When I arrived a couple of years ago, the members were just beginning to work through several issues facing our association," Don said. "As we moved forward, Tri-State increased its lines of communication with us, which in turn increased Tri-State's understanding of our concerns."

Don lists the Member Communications Advisory Council, new manager orientation and director orientation as ways Tri-State has multiplied its engagement with members.

WHEATLAND: ONE METER FOR EVERY SQUARE MILE, RELIABILITY IS CRITICAL

"No one likes a power outage. Any transmission outage can affect all of our members," Don said. "In our area, our consumers can be hit hard by an outage as most of them live some distance from one another, as is the case in many rural areas," Don said.

As a member and owner of a generation and transmission association, we can rely on Tri-State to troubleshoot issues. Last year, several back-to-back transmission outages hit Wheatland. Don reached out to Tri-State, who worked with two other transmission providers to figure out what was causing the outage. Since then, Wheatland and its consumers have not had a single transmission outage from the issue.

“AS WE MOVED FORWARD, TRI-STATE INCREASED ITS LINES OF COMMUNICATION WITH US, WHICH IN TURN INCREASED TRI-STATE’S UNDERSTANDING OF OUR CONCERNS.”

"WE ALL FACE SIMILAR CHALLENGES AND THAT BRINGS US ALL TOGETHER."

OTERO COUNTY ELECTRIC

SOUTH CENTRAL NEW MEXICO // MARIO ROMERO, CEO

EMPLOYEES: 67 **METERS:** 19,000 **SERVICE AREA:** NEARLY 10,000 SQUARE MILES
FACILITIES: CLOUDCROFT, HEADQUARTERS; ALTO & CARRIZOZO, OFFICES; TULAROSA, WAREHOUSE
LOAD SERVED: 20% COMMERCIAL; 80% RESIDENTIAL

Mario Romero embodies the next generation of electric cooperative leadership. In 2002, he completed his senior undergraduate project on Automatic Metering Infrastructure as an Otero County Electric intern. After graduating, Otero hired Mario as a full-time system engineer. The following year Otero launched a pilot of his project, then fully adopted it over the next few years. Before becoming CEO in November of 2014, Mario worked as the engineering manager for 12 years.

POWER MAKES IT POSSIBLE™

“It is critical for us to educate our members about what is affecting their rates and how we as a distribution cooperative address rate changes,” Mario said. “We also want our members to understand the value of the cooperative model and the electricity it delivers.”

Tri-State helps its members convey the value of their service to their customers through education and marketing campaigns like Power Makes It Possible. “Being a member of Tri-State allows us to leverage these types of campaigns that could be otherwise out of reach for some members. Because of campaigns like Power, our membership will better understand the value of cooperative membership and how electricity benefits them,” Mario said.

“The Power campaign focuses on the co-ops, its local people and local businesses,” he said. “It benefits us to have a local feel on education and marketing materials Tri-State creates for us.”

WE ARE FAMILY

When faced with obstacles or complex issues, Mario appreciates having the association and members to lean on.

“We all face similar challenges and that brings us all together. We have resources through networking and relationships to be able to call any number of other managers or any number of people at Tri-State to ask a question if we don’t know the answer,” Mario said.

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

The Board of Directors of Tri-State Generation and Transmission Association, Inc.

We have audited the accompanying consolidated statements of financial position of Tri-State Generation and Transmission Association, Inc. (the Association) as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Association's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Association's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tri-State Generation and Transmission Association, Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

Ernst + Young LLP

Denver, Colorado
March 14, 2016

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

As of December 31,	2015	2014
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,486,518	$ 5,193,236
Construction work in progress	216,279	206,097
Total electric plant	5,702,797	5,399,333
Less allowances for depreciation and amortization	(2,240,732)	(2,129,173)
Net electric plant	3,462,065	3,270,160
Other plant	227,957	210,694
Less allowances for depreciation, amortization and depletion	(73,471)	(58,117)
Net other plant	154,486	152,577
Total property, plant and equipment	3,616,551	3,422,737
Other assets and investments		
Investments in other associations	123,686	117,976
Investments in and advances to coal mines	16,221	15,016
Restricted cash and investments	1,000	39,376
Intangible assets	25,634	32,958
Other noncurrent assets	12,139	12,531
Total other assets and investments	178,680	217,857
Current assets		
Cash and cash equivalents	144,587	92,468
Restricted cash and investments	9,530	9,784
Deposits and advances	21,673	22,224
Accounts receivable—Members	106,216	105,723
Other accounts receivable	14,270	25,693
Coal inventory	59,277	40,673
Materials and supplies	85,501	80,069
Total current assets	441,054	376,634
Deferred charges		
Regulatory assets	415,081	426,043
Prepayment—NRECA Retirement Security Plan	49,146	54,665
Other	122,535	156,200
Total deferred charges	586,762	636,908
Total assets	**$ 4,823,047**	**$ 4,654,136**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 952,082	$ 908,669
Accumulated other comprehensive income (loss)	589	(828)
Noncontrolling interest	108,757	109,302
Total equity	1,061,428	1,017,143
Long-term debt	3,273,538	3,145,246
Total capitalization	4,334,966	4,162,389
Current liabilities		
Member advances	9,403	14,576
Accounts payable	96,098	103,177
Accrued expenses	30,045	30,005
Accrued interest	34,332	32,517
Accrued property taxes	27,395	26,010
Current maturities of long-term debt	91,419	92,802
Total current liabilities	288,692	299,087
Deferred credits and other liabilities		
Regulatory liabilities	45,000	45,000
Deferred income tax liability	28,629	17,230
Intangible liabilities	6,221	9,424
Asset retirement obligations	55,215	53,754
Other	57,423	59,121
Total deferred credits and other liabilities	192,488	184,529
Accumulated postretirement benefit and postemployment obligations	6,901	8,131
Total equity and liabilities	**$ 4,823,047**	**$ 4,654,136**

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,	2015	2014	2013
Operating revenues			
Member electric sales	$ 1,125,699	$ 1,101,471	$ 1,091,103
Non-member electric sales	120,234	197,497	172,102
Other	89,515	96,123	77,958
	1,335,448	1,395,091	1,341,163
Operating expenses			
Purchased power	305,045	327,445	322,059
Fuel	231,537	293,033	287,647
Production	235,398	229,933	209,816
Transmission	153,443	145,396	138,684
General and administrative	24,708	28,591	24,325
Depreciation, amortization and depletion	152,718	128,712	121,818
Coal mining	36,130	40,849	29,889
Other	18,500	19,255	18,337
	1,157,479	1,213,214	1,152,575
Operating margins	**177,969**	**181,877**	**188,588**
Other income			
Interest income	4,355	11,076	17,288
Capital credits from cooperatives	9,189	8,684	10,922
Other income	3,981	3,573	3,344
	17,525	23,333	31,554
Interest expense, net of amounts capitalized	142,570	142,357	149,463
Income taxes	—	—	—
Net margins including noncontrolling interest	52,924	62,853	70,679
Net loss attributable to noncontrolling interest	489	1,383	2,233
Net margins attributable to the Association	**$ 53,413**	**$ 64,236**	**$ 72,912**

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,	2015	2014	2013
Net margins including noncontrolling interest	$ 52,924	$ 62,853	$ 70,679
Other comprehensive income (loss):			
Unrealized gain (loss) on securities available for sale	(125)	—	278
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,528	(4,194)	—
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	14	31	(358)
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	1,417	(4,163)	(80)
Comprehensive income including noncontrolling interest	54,341	58,690	70,599
Net comprehensive loss attributable to noncontrolling interest	489	1,383	2,233
Comprehensive income attributable to the Association	**$ 54,830**	**$ 60,073**	**$ 72,832**

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,	2015	2014	2013
Patronage capital equity at beginning of year	$ 908,669	$ 865,379	$ 802,467
Net margins attributable to the Association	53,413	64,236	72,912
Retirement of patronage capital	(10,000)	(20,946)	(10,000)
Patronage capital equity at end of year	**952,082**	**908,669**	**865,379**
Accumulated other comprehensive income (loss) at beginning of year	(828)	3,335	3,415
Unrealized gain (loss) on securities available for sale	(125)	—	278
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,528	(4,194)	—
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	14	31	(358)
Accumulated other comprehensive income (loss) at end of year	**589**	**(828)**	**3,335**
Noncontrolling interest at beginning of year	109,302	110,740	113,027
Net loss attributable to noncontrolling interest	(489)	(1,383)	(2,233)
Equity distribution to noncontrolling interest	(56)	(55)	(54)
Noncontrolling interest at end of year	**108,757**	**109,302**	**110,740**
Total equity at end of year	**$ 1,061,428**	**$ 1,017,143**	**$ 979,454**

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,	2015	2014	2013
Operating activities			
Net margins including noncontrolling interest	$ 52,924	$ 62,853	$ 70,679
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	152,718	126,693	118,776
Amortization of intangible asset	7,324	7,324	7,324
Amortization of NRECA Retirement Security Plan prepayment	5,520	5,519	5,457
Amortization of debt issuance costs	1,870	1,356	897
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(7,179)	(6,465)	(7,053)
Prepayment—NRECA Retirement Security Plan	—	—	(71,160)
Recognition of deferred revenue	—	(20,000)	—
Change in restricted cash and investments	29,113	—	(390)
Changes in operating assets and liabilities:			
Accounts receivable	10,936	(6,460)	7,000
Coal inventory	(18,604)	3,057	17,524
Materials and supplies	(5,432)	(4,593)	(4,119)
Accounts payable and accrued expenses	(12,188)	(5,923)	13,090
Accrued interest	1,814	7,909	(1,061)
Accrued property taxes	1,385	2,507	(189)
Other deferred credits - BNSF settlement	(29,381)	—	—
Other	21,324	13,076	(5,089)
Net cash provided by operating activities	**212,144**	**186,853**	**151,686**
Investing activities			
Purchases of plant	(290,428)	(221,613)	(212,703)
Changes in deferred charges	9,031	(8,263)	(1,849)
Proceeds from other investments	321	15,270	1,578
Net cash used in investing activities	**(281,076)**	**(214,606)**	**(212,974)**
Financing activities			
Member advances	(7,041)	2,227	(2,129)
Payments of long-term debt	(113,063)	(1,739,835)	(196,490)
Proceeds from issuance of debt	240,183	1,674,977	258,873
Debt refinancing transaction costs	—	(184,073)	—
Decrease in advance payments to RUS	—	137,727	130,257
Retirement of patronage capital	(8,286)	(20,582)	(10,711)
Proceeds from investment in securities pledged as collateral	8,931	8,723	8,410
Change in restricted cash and investments	327	48,000	(15,357)
Net cash provided by (used in) financing activities	**121,051**	**(72,836)**	**172,853**
Net increase (decrease) in cash and cash equivalents	**52,119**	**(100,589)**	**111,565**
Cash and cash equivalents – beginning	**92,468**	**193,057**	**81,492**
Cash and cash equivalents – ending	**$ 144,587**	**$ 92,468**	**$ 193,057**
Supplemental cash flow information:			
Cash paid for interest	$ 154,657	$ 152,344	$ 166,828
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 2,173	$ (4,691)	$ 5,276
Renewal of transmission right of way easements	27,447	—	—

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. ("the Association") is a taxable wholesale electric power generation and transmission cooperative organized for the purpose of providing electricity to our 44 member distribution systems ("Members"), that serve major parts of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our electric power to other utilities in the region pursuant to long-term contracts and spot sale arrangements. In 2015, 2014 and 2013, total megawatt-hours sold were 17.8, 18.7 and 18.6 million, respectively, of which 89, 85 and 86 percent, respectively, were sold to Members. Total revenue from electric sales was $1.2, $1.3, and $1.3 billion for 2015, 2014 and 2013 of which 90, 85 and 86 percent, respectively, was from Member sales. Energy resources were provided by generation and purchased power, of which 63, 63 and 64 percent were from generation for 2015, 2014 and 2013, respectively.

We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members and extending through 2040 for the remaining two Members, and subject to automatic extension thereafter until either party provides at least a two year notice of its intent to terminate. Each contract obligates us to sell and deliver to the Member and obligates the Member to purchase and receive from us at least 95 percent of the power it requires for the operation of its system. Each Member may elect to provide up to 5 percent of its requirements from distributed or renewable generation owned or controlled by the Member. As of December 31, 2015, 16 Members have made such an election.

Revenue from one Member, United Power, Inc., was $147.1 million, or 13.1 percent of our Member revenue, and 11 percent of our overall revenue, in 2015. No other Member exceeded 10 percent of our Member revenue or our overall revenue in 2015.

Power is provided to Members at rates determined by the Board of Directors ("Board"). Rates are designed to recover all costs and provide margins to increase Members' equity and to meet certain long-term debt financial covenants, including a debt service ratio ("DSR") requirement and equity to capitalization ratio ("ECR") requirement.

We supply wholesale power to our Members through the utilization of a portfolio of resources, including generating facilities, long-term purchase contracts and forward, short-term and spot market 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 generating facilities, we have direct ownership and investment in coal mines.

We, including our subsidiaries, employ 1,561 people, of which 361 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 11—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 three jointly owned generation facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Craig Station Units 1 and 2 (operated by us (“Yampa Project”)), the Missouri Basin Power Project (“MBPP”) (operated by Basin Electric Power Cooperative (“Basin”)) and the San Juan Project (operated by Public Service Company of New Mexico). Each participant in these agreements receives a portion of the total output of the generation facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and operating expenses is included in our consolidated financial statements.

VARIABLE INTEREST ENTITIES: We evaluate our arrangements and relationships with other entities, including our investments in other associations and investments in coal mines, 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 in, meets the criteria of a variable interest entity. An entity is considered to be a variable interest entity when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. In making this assessment, we consider the potential that our arrangements and relationships with other entities provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of an entity, the ability to directly or indirectly make decisions about the entity’s activities and other factors. If an entity that we have a variable interest in meets the criteria of a variable interest entity, we must determine whether we are the primary beneficiary of that entity. The primary beneficiary is the entity that has the power to direct any of 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 11—Variable Interest Entities.

ACCOUNTING FOR RATE REGULATION: We are subject to the accounting requirements related to regulated operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board, which has budgetary and rate-setting authority, if it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from our Members based on rates approved by our Board in accordance with our rate policy. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Members based on rates approved by our Board in accordance with our rate policy. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses concurrent with their recovery in rates.

Regulatory assets and liabilities are as follows (thousands):

	2015	2014
Regulatory assets		
Deferred income tax expense (1)	$ 28,629	$ 17,230
Deferred prepaid lease expense- Craig 3 Lease (2)	16,183	22,656
Deferred prepaid lease expense- Springerville 3 Lease (3)	92,878	95,168
Goodwill – J.M. Shafer (4)	60,541	63,390
Goodwill – Colowyo Coal (5)	41,327	43,526
Deferred debt prepayment transaction costs (6)	175,444	184,073
Other	79	—
	415,081	426,043
Regulatory liabilities		
Deferred revenues (7)	45,000	45,000
Net regulatory asset	$ 370,081	$ 381,043

(1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.
(2) Deferral of loss on acquisition related to the Craig Generating Station ("Craig Station") Unit 3 prepaid lease expense upon acquisitions of equity interests in 2002 and 2006. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation and amortization expense in the amount of $6.5 million annually through the remaining original life of the lease ending in 2018 and recovered from our Members in rates.
(3) Deferral of loss on acquisition related to the Springerville Generating Station Unit 3 ("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 and amortization expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Members in rates.
(4) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP ("TCP") in December 2011. Goodwill is being amortized to depreciation and amortization expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Members in rates.
(5) Represents goodwill related to our acquisition of Colowyo Coal Company LP ("Colowyo Coal") in December 2011. Goodwill is being amortized to depreciation and amortization expense through the 44-year period ending in 2056 and recovered from our Members in rates.
(6) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation and amortization expense in the amount of $8.6 million annually over the 21.4-year average life of the new debt issued and recovered from our Members in rates.
(7) Represents deferral of the recognition of $10 million of non-member electric sales revenue received in 2008 and $35 million of non-member electric sales revenue in 2011. These deferred non-member electric sales revenues will be refunded to Members through reduced rates when recognized in non-member electric sales revenue in future periods.

SEGMENT REPORTING: We are organized for the purpose of supplying wholesale power to our Members and do so through the utilization of a portfolio of resources, including generating facilities, long-term purchase contracts and forward, short-term and spot market energy purchases. In support of our coal generating resources, we have direct ownership and investments 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.

BUSINESS COMBINATIONS: We account for business acquisitions by applying the accounting standard related to business combinations. In accordance with this method, the identifiable assets acquired, the liabilities assumed and any noncontrolling interests in the acquired entities are required to be recognized at their acquisition date fair values. We typically engage an independent valuation firm to determine the acquisition date fair values of most of the acquired assets and assumed liabilities. The excess of total consideration transferred over the net assets acquired is recognized as goodwill. Acquisition-related costs such as legal fees, accounting services fees and valuation fees, are expensed as incurred. We are required to consolidate these acquired entities.

If an acquisition does not result in acquiring a business, the transaction is accounted for as an acquisition of assets. This method requires measurement and recognition of the acquired net assets based upon the amount of cash transferred and the amount paid for acquisition-related costs. There is no goodwill recognized in an acquisition of assets.

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.

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 of 4.4, 4.7 and 4.8 percent were used for 2015, 2014 and 2013, respectively. The amount of interest capitalized during construction was $13.5, $15.0 and $13.0 million during 2015, 2014 and 2013, 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.

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: The accounting for lease transactions in conformity with GAAP requires management to make various assumptions, including the discount rate, the fair market value of the leased assets and the estimated useful life, in order to determine whether a lease should be classified as operating or capital.

We are the lessor under power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey the right to use our power generating equipment for a stated period of time. The lease revenues from these arrangements are included in other operating revenue on the consolidated statements of operations. We are the lessee under power purchase arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to us the right to use power generating equipment for a stated period of time. These are included in other operating expenses on the consolidated statements of operations. See Note 8—Leases.

INVESTMENTS IN OTHER ASSOCIATIONS: Investments in other associations includes investments in the patronage capital of other cooperatives (accounted for using the cost method) and other required investments in the organizations. Under this method, our investment in a cooperative increases when a cooperative allocates patronage capital credits to us and it decreases when we receive a cash retirement of the allocated capital credits from the cooperative. A cooperative allocates its patronage capital credits to us based upon our patronage (amount of business done) with the cooperative.

Investments in other associations are as follows (thousands):

	2015	2014
Basin Electric Power Cooperative	$ 84,875	$ 80,250
National Rural Utilities Cooperative Finance Corporation	26,808	26,695
CoBank, ACB	6,212	5,518
Western Fuels Association, Inc.	2,275	2,338
Other	3,516	3,175
Investments in other associations	$ 123,686	$ 117,976

INVESTMENTS IN AND ADVANCES TO COAL MINES: We have direct ownership and investments in coal mines to support our coal generating resources. We, and certain participants in the Yampa Project, are members of Trapper Mining, Inc. ("Trapper Mining"), which is organized as a cooperative and is the owner and operator of the Trapper Mine near Craig, Colorado. Our investment in Trapper Mining is recorded using the equity method. In addition, we have ownership in Western Fuels Association, Inc. ("WFA"), which is the owner of Western Fuels-Wyoming, Inc. ("WFW"), the owner and operator of the Dry Fork Mine near Gillette, Wyoming. We, through our ownership in WFA, advance funds to the Dry Fork Mine.

Investments in and advances to coal mines are as follows (thousands):

	2015	2014
Investment in Trapper Mine	$ 14,072	$ 13,650
Advances to Dry Fork Mine	2,149	1,366
Investments in and advances to coal mines	$ 16,221	$ 15,016

CASH AND CASH EQUIVALENTS: We consider highly liquid investments with an original maturity of three months or less to be cash equivalents.

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

We have investments in U.S. Treasury Notes pledged as collateral in connection with the in-substance defeasance for the principal outstanding and future interest payments on the Coal Contract Receivable Collateralized Bonds ("Colowyo Bonds"). The balances in these investments are described as investments in securities pledged as collateral in the table below. As of December 31, 2015, the entire $8.7 million balance of the defeasance investment is for Colowyo Bond debt payments due within one year and is, therefore, a current asset on the consolidated statements of financial position. The Colowyo Bonds mature in November 2016.

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

Restricted cash and investments are as follows (thousands):

	2015	2014
Investments in securities pledged as collateral	$ 8,671	$ 9,192
Funds restricted by contract	859	592
Restricted cash and investments - current	9,530	9,784
BNSF settlement	—	29,381
Funds restricted by contract	1,000	1,000
Investments in securities pledged as collateral	—	8,995
Restricted cash and investments - noncurrent	1,000	39,376
Total restricted cash and investments	$ 10,530	$ 49,160

MARKETABLE SECURITIES: We hold marketable securities in connection with the directors' and executives' elective deferred compensation plans which consist of investments in stock funds, bond funds and money market funds. These securities are classified as available-for-sale securities. At December 31, 2015, the cost and estimated fair value of the investments based upon their active market value (Level 1 inputs) were $1.0 and $1.2 million, respectively, with a net unrealized gain balance of $129,000. At December 31, 2014, the cost and estimated fair value of the investments were $1.1 and $1.4 million, respectively, with a net unrealized gain balance of $254,000. The estimated fair value of the investments is included in other noncurrent assets on the consolidated statements of financial position. The unrealized gains at December 31, 2015 and 2014 are reported as a component of accumulated other comprehensive income as of those dates. Changes in the net unrealized gains or losses are reported as a component of comprehensive income.

We hold U.S. Treasury Notes to maturity in connection with the December 2011 defeasance of the Colowyo Bonds and these are included in restricted cash and investments on the statements of financial position. Since they will be held to maturity, the notes are carried at amortized cost. As of December 31, 2015, the defeasance investment of $8.7 million consisted of a principal amount of $7.4 million, an unamortized premium of $113,000 and cash of $1.1 million. As of December 31, 2014, the defeasance investment of $18.2 million consisted of a principal amount of $16.4 million, an unamortized premium of $371,000 and cash of $1.4 million.

INVENTORIES: Coal inventories at our owned generating stations are stated at LIFO (last-in, first-out) cost and were $42.2 and $22.2 million at December 31, 2015 and 2014, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2014, we realized lower coal fuel expense of $596,000 as a result of a LIFO inventory liquidation at our generating stations.

OTHER DEFERRED CHARGES: We make expenditures for preliminary surveys and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects. If construction results, the preliminary survey and investigation expenditures will be reclassified to electric plant—construction work in progress. If the work is abandoned, the related preliminary survey and investigation expenditures will be charged to the appropriate operating expense account or the expense could be deferred as a regulatory asset to be recovered from our Members in rates subject to approval by our Board, which has budgetary and rate-setting authority. As of December 31, 2015, preliminary surveys and investigations was primarily comprised of expenditures for the Holcomb Station Project of $86.7 million (see Note 12—Commitments and Contingencies—Legal). In December 2015, $28.5 million of preliminary survey charges related to the Eastern Plains Transmission Project was capitalized as part of the Burlington-Wray 230kV transmission line project and is included in electric plant-construction work in progress on the consolidated statements of financial position.

We make advance payments to the operating agents of jointly owned facilities. See Note 3—Property, Plant and Equipment—Jointly Owned Facilities.

Other deferred charges are as follows (thousands):

	2015	2014
Preliminary surveys and investigations	$ 107,146	$ 131,693
Advances to operating agents of jointly owned facilities	11,537	20,567
Other	3,852	3,940
Total other deferred charges	$ 122,535	$ 156,200

DEBT ISSUANCE COSTS: We adopted Accounting Standards Update ("ASU") 2015-03, *Interest — Imputation of Interest (Subtopic 835-30)* and ASU 2015-15, *Interest – Imputation of Interest (Subtopic 835-30) Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* Accordingly, we accounted 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. The adoption of these amendments resulted in $21.2 million and $22.3 million of debt issuance costs being presented as a direct deduction from long-term debt as of December 31, 2015 and 2014. The $22.3 million of debt issuance costs as of December 31, 2014 were retrospectively adjusted as a change in accounting principle and were previously reported in other deferred charges.

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

Coal mines: We have asset retirement obligations for the final reclamation costs and post-reclamation monitoring related to the Colowyo Mine, the New Horizon Mine, and the Fort Union Mine.

Fossil steam generation: We, including our undivided interest in jointly owned facilities, have asset retirement obligations related to equipment, dams, ponds, wells and underground storage tanks at the fossil steam generating stations.

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

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

	2015	2014
Asset retirement obligation at beginning of year	$ 53,754	$ 52,585
Liabilities incurred	1,802	1,366
Liabilities settled	(3,028)	(5,729)
Accretion expense	3,324	2,250
Change in cash flow estimate	(637)	3,282
Asset retirement obligation at end of year	$ 55,215	$ 53,754

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 far value.

MEMBERSHIPS: There are 44 $5 memberships outstanding at December 31, 2015 and 2014.

PATRONAGE CAPITAL: Our net margins are treated as advances of capital by our Members and are allocated to our Members on the basis of their electricity purchases from us. Net losses, should they occur, are not allocated to Members, but are offset by future margins. Margins not 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.

ACCOUNTS RECEIVABLE—MEMBERS AND OTHER: Receivables are primarily related to electric sales to Members and electric sales and other transactions with electric utilities. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible.

OTHER OPERATING REVENUE: Other operating revenue consists primarily of wheeling revenue, lease revenue, coal sales and revenue from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. The lease revenue is primarily from certain power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to others the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine per a contract ending in 2017 to other joint owners in the Yampa Project (the "Yampa Participants"). The associated Colowyo Mine expenses are included in coal mining, depreciation and amortization and interest expense on the consolidated statements of operations.

INCOME TAXES: We are a non-exempt cooperative subject to federal and state taxation and, as a cooperative, are allowed a tax exclusion for margins allocated as patronage capital. The liability method of accounting for income taxes is utilized, whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.

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 $1.6 and $1.5 million at December 31, 2015 and 2014, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was $108,630, $(452,500) and $2.6 million in 2015, 2014 and 2013, respectively.

EVALUATION OF SUBSEQUENT EVENTS: We evaluated subsequent events through March 14, 2016, which is the date when the financial statements were issued.

NEW ACCOUNTING PRONOUNCEMENTS: In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. In July 2015, FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. ASU 2014-09 replaces current revenue guidance, which was based on a risks and rewards model, with a transfer of control model. The core principle under the new transfer of control model states that revenue should be recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. To achieve the core principle, this amendment requires the following steps: (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This amendment also requires additional quantitative and qualitative disclosures sufficient enough to enable users of financial information to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, this amendment is effective for the fiscal year beginning January 1, 2018 using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach with the cumulative effect of initially adopting the standard recognized at the date of adoption (which includes footnote disclosures). Reporting entities have the option to adopt the standard as early as the original January 1, 2017 effective date of this amendment. We are currently evaluating the impact of this amendment on our financial position and results of operations.

In August 2014, the FASB issued ASU 2014-15, *Presentation of Financial Statements Going Concern (Subtopic 205-40); Disclosures of Uncertainties about an Entity's Ability to Continue as a Going Concern.* The amendment in this ASU requires management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern, which is currently performed by the external auditors. Management will be required to perform this assessment for both interim and annual reporting periods and must make certain disclosures if it concludes that substantial doubt exists. Substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meets its obligations as they become due within one year after the date that that the financial statements are issued (or within one year after the date that the financial statements are available to be issued when applicable). The amendment is effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2016. We are currently evaluating the impact of this amendment on our financial position and results of operations. The adoption of this update is not expected to have a material impact on the financial position or results of operations.

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

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740); Balance Sheet Classification of Deferred Taxes.* The amendments in this ASU simplify the presentation of deferred income taxes. Deferred tax assets and liabilities must all be classified as noncurrent. This amendment is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. We adopted this update in 2015 and it did not have a material impact on our financial position or results of operations.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. The amendments in this ASU require that equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) be measured at fair value, with subsequent changes in fair value recognized in net income. An entity may choose to measure equity investments that do not have readily determinable fair value at cost minus impairment. The pronouncement impacts financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. Also, an entity should present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk if the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. The amendments are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application by public business entities to financial statements of fiscal years or interim periods that have not yet been issued or, by all other entities, that have not yet been made available for issuance are permitted as of the beginning of the fiscal year of adoption. An entity should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The amendments related to equity securities without readily determinable fair values (including disclosure requirements) should be applied prospectively to equity investments that exist as of the date of adoption of the update. We are currently evaluating the impact of this amendment on our financial position and results of operations.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842).* This amendment requires a lessee to recognize substantially all leases (whether operating or finance leases) on the balance sheet as a right-of-use asset and an associated lease liability. Short-term leases of 12 months or less are excluded from this amendment. A right-of-use asset represents a lessee's right to use (control the use of) the underlying asset for the lease term. A lease liability represents a lessee's liability to make lease payments. The right-of-use asset and the lease liability are initially measured at the present value of the lease payments over the lease term. For finance leases, the lessee subsequently recognizes interest expense and amortization of the right-of-use asset, similar to accounting for capital leases under current GAAP. For operating leases, the lessee subsequently recognizes straight-line lease expense over the life of the lease. Lessor accounting remains substantially the same as that applied under current GAAP. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. The guidance is to be applied using a modified retrospective transition method with the option to elect a package of practical expedients. We are currently evaluating the impact of this amendment on our financial position and results of operations.

NOTE 3—PROPERTY, PLANT AND EQUIPMENT

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

ELECTRIC PLANT: Our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (thousands):

	Annual Depreciation Rate			2015	2014
Generation plant	0.44 %	to	3.16 %	$ 3,498,248	$ 3,379,305
Transmission plant	2.00 %	to	2.88 %	1,294,151	1,161,462
General plant	3.00 %	to	33.33 %	430,842	392,963
Other	2.80 %	to	5.60 %	263,277	259,506
Electric plant in service (at cost)				5,486,518	5,193,236
Construction work in progress				216,279	206,097
Less allowances for depreciation and amortization				(2,240,732)	(2,129,173)
Electric plant				$ 3,462,065	$ 3,270,160

At December 31, 2015, we had $82.8 million of commitments to complete construction projects, of which approximately $63.6, $14.3 and $4.9 million are expected to be incurred in 2016, 2017 and 2018, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2015 (these electric plant in service, accumulated depreciation and construction work in progress amounts are included in the electric plant table above) (thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Station Units 1 and 2	24.00 %	$ 345,937	$ 229,464	$ 23,518
MBPP - Laramie River Station	24.13 %	389,283	288,386	13,791
San Juan Project – San Juan Unit 3	8.20 %	82,754	61,369	562
Total		$ 817,974	$ 579,219	$ 37,871

OTHER PLANT: Other plant consists of mine assets (discussed below) and non-utility assets (which consist of piping and equipment specifically related to providing steam and water from the Escalante Generating Station to a third party for the use in the production of paper).

We own 100 percent of Western Fuels-Colorado ("WFC"), a limited liability company organized for the purpose of acquiring coal reserves and supplying coal to us, which is the owner and operator of the New Horizon Mine near Nucla, Colorado. WFC also owns Colowyo Coal, which is the owner and operator of the Colowyo Mine, a large surface coal mine near Craig, Colorado. We also own a 50 percent undivided ownership in the land and the rights to mine the property known as Fort Union Mine. Our share of the coal provided from these mines is primarily used by us for generation at our generating facilities. The expenses related to this coal used by us are included in fuel expense on the consolidated statements of operations.

Other plant assets are as follows (thousands):

	2015	2014
Colowyo Mine assets	$ 166,157	$ 152,549
New Horizon Mine assets	48,373	44,812
Fort Union Mine assets	1,158	2,007
Accumulated depreciation and depletion	(67,601)	(52,580)
Net mine assets	148,087	146,788
Non-utility assets	12,269	11,326
Accumulated depreciation	(5,870)	(5,537)
Net non-utility assets	6,399	5,789
Net other plant	$ 154,486	$ 152,577

NOTE 4—INTANGIBLES

INTANGIBLE ASSETS: The December 2011 acquisition of TCP resulted in recording an intangible asset in the amount of $55.5 million relating to a contractual obligation that TCP has to a third party under a purchase power agreement (the "PPA"). The $55.5 million intangible asset represents the amount that the PPA contract terms were above market value at the acquisition date and is being amortized on a straight-line basis over the remaining life of the PPA through June 30, 2019. The straight-line method is consistent with the terms of the PPA as this contract is for a fixed amount of capacity at a fixed capacity rate that stays constant over the term of the contract. The amortization of the PPA intangible asset is accounted for as a reduction of the revenue generated by the PPA and is included in other operating revenue. The amortization was $7.3 million in each of the years 2015, 2014 and 2013 and will be recognized over each of the next four years as follows (thousands):

2016	$ 7,324
2017	7,324
2018	7,324
2019	3,662
	$ 25,634

INTANGIBLE LIABILITIES: The December 2011 acquisition of Colowyo Coal resulted in recording an intangible liability of $18.0 million relating to a contractual obligation that Colowyo Coal has to sell coal to the Yampa Participants through 2017. The $18.0 million intangible liability represents the amount that the coal sale contract terms were below market at the acquisition date and is being amortized based upon the contracted tonnage with the Yampa Participants over the remaining life of the coal contract ending December 31, 2017. The intangible liability balance of $6.2 and $9.4 million as of December 31, 2015 and 2014, respectively, is included in intangible liabilities. The amortization of the Colowyo Coal intangible liability is accounted for as an increase in other operating revenue. An amortization benefit of $3.2, $3.2 and $2.5 million was recognized in 2015, 2014 and 2013, respectively, and the recognition of the benefit over the next two years is estimated to be as follows (thousands):

2016	$ 3,125
2017	3,096
	$ 6,221

NOTE 5 – LONG-TERM DEBT

The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement except for two unsecured notes in the aggregate amount of $55.9 million as of December 31, 2015. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. The Colowyo Bonds are secured by funds deposited with the trustee as part of the in-substance defeasance and an unconditional guarantee by us. All long-term debt contains certain restrictive financial covenants, including a DSR requirement and ECR requirement.

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

	2015	2014
Mortgage notes payable		
3.66% to 8.08% CFC, 5.96% average for 2015, due through 2028	$ 86,979	$ 92,977
2.63% to 6.17% CoBank, ACB, 4.35% average for 2015, due through 2042	278,086	287,798
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	250,000	250,000
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	250,000	250,000
First Mortgage Bonds, Series 2010A, 6.00% due 2040	500,000	500,000
First Mortgage Obligation, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000	180,000
First Mortgage Obligation Series 2014B, Tranche 2, 4.30%, due through 2039	20,000	20,000
First Mortgage Obligation Series 2014B, Tranche 3, 4.45%, due through 2045	550,000	550,000
First Mortgage Obligation, Series 2009C, Tranche 1, 6.00%, due through 2019	108,571	135,714
First Mortgage Obligation, Series 2009C, Tranche 2, 6.31%, due through 2021	110,000	110,000
Variable rate CFC, as determined by CFC, 2.90% average for 2015, due through 2026	644	687
Variable rate CFC, LIBOR-based term loan, 1.48% average for 2015, due through 2049	102,220	102,220
Variable rate CoBank, ACB, LIBOR-based term loan, 1.74% average for 2015, due through 2044	102,220	102,220
Variable rate, Revolving Credit Agreement, LIBOR-based revolving credit, 1.25% average for 2015, due through 2019	271,000	50,000
Pollution control revenue bonds		
City of Gallup, NM, 5.00%, Series 2005, due through 2017	10,815	15,840
Moffat County, CO Variable Rate Demand Series 2009, 0.06% average for 2015, due 2036	46,800	46,800
Springerville certificates		
Series A, 6.04%, due through 2018	89,968	124,779
Series B, 7.14%, due through 2033	405,000	405,000
Colowyo Coal		
Colowyo Bonds, 10.19%, due through 2016	7,693	15,899
Other	1,683	2,536
Total debt	$ 3,371,679	$ 3,242,470
Less debt issuance costs	(21,201)	(22,254)
Less debt discounts	(8,739)	(8,894)
Plus debt premiums	23,218	26,726
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,364,957	$ 3,238,048
Less current maturities	(91,419)	(92,802)
Long-term debt	$ 3,273,538	$ 3,145,246

On October 30, 2014, we issued the First Mortgage Bonds, Series 2014 E-1 and E-2 (“Series 2014 Bonds”) in an aggregate amount of $500 million. In connection with the Series 2014 Bonds, we entered into a registration rights agreement. On July 30, 2015, we commenced an offer to exchange the $500 million aggregate principal amount of the Series 2014 Bonds. The exchange offer satisfied our obligations under the registration rights agreement. The exchange offer did not represent a new financing transaction and there were no proceeds to us when the exchange offer was completed in September 2015.

We have a secured revolving credit facility with Bank of America, N.A.(“Bank of America”) and CoBank, ACB as Joint Lead Arrangers in the amount of $750 million (“Revolving Credit Agreement”). We had outstanding borrowings of $271 million and $50 million at December 31, 2015 and December 31, 2014, respectively. There is a 364-day, direct pay letter of credit issued under the Revolving Credit Agreement and provided by Bank of America, N.A. for the $46.8 million Moffat County, CO, Variable Rate Demand Pollution Control Revenue Refunding Bonds, Series 2009. In November 2015, the letter of credit from Bank of America was extended for an additional 364 days to mature in January 2017. As of December 31, 2015, the availability under the Revolving Credit Agreement was $431 million.

Annual maturities of total debt adjusted for debt issuance costs, discounts and premiums at December 31, 2015 are as follows (thousands):

2016	$ 91,419
2017	108,037
2018	78,322
2019 (1)	368,776
2020	84,834
Thereafter	2,633,569
	$ 3,364,957

(1) Annual maturities in 2019 include $271 million of outstanding borrowings under the Revolving Credit Agreement.

NOTE 6—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 utilize observable market data in active markets for identical assets or liabilities.

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

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

In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. The assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability.

Marketable Securities

We hold marketable securities in connection with the directors' and executives' elective deferred compensation plans which consist of investments in stock funds, bond funds and money market funds. These securities are classified as available-for-sale and are measured at fair value on a recurring basis. The estimated fair value of the investments is included in other noncurrent assets on our consolidated statements of financial position. The unrealized gains are reported as a component of accumulated other comprehensive income. Changes in the net unrealized gains or losses are reported as a component of comprehensive income. The carrying amounts and fair values of our marketable securities are as follows (thousands):

	As of December 31, 2015		As of December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Marketable securities	$ 1,022	$ 1,151	$ 1,095	$ 1,349

The estimated fair value of the investments is based upon their active market value (Level 1 inputs) and is included in other noncurrent assets on our consolidated statements of financial position. The unrealized gains at December 31, 2015 and December 31, 2014 are reported as a component of accumulated other comprehensive income as of those dates. Changes in the net unrealized gains or losses are reported as a component of comprehensive income.

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 carrying amounts and fair values of our debt are as follows (thousands):

	2015		2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	$ 3,371,679	$ 3,616,946	$ 3,242,470	$ 3,716,513

NOTE 7 – INCOME TAXES

We had no income tax expense or benefit in 2015, 2014 and 2013.

The liability method of accounting for income taxes is utilized, whereby changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.

Under the liability method, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and for income tax purposes.

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

	2015	2014
Deferred tax assets		
Safe harbor lease receivables	$ 35,945	$ 38,218
Net operating loss carryforwards	152,936	131,935
Alternative minimum tax credit carryforwards	3,834	3,834
Deferred revenues	16,933	16,933
Colowyo Coal- coal contract intangible liability	2,341	3,547
Other	35,332	46,856
	247,321	241,323
Deferred tax liabilities		
Basis differences- property, plant and equipment	160,494	152,497
Capital credits from other associations	38,663	36,790
Deferred debt prepayment transaction costs	66,020	69,266
Other	10,773	—
	275,950	258,553
Net deferred tax liability	$ (28,629)	$ (17,230)

The $11.4 million increase in the net deferred tax liability from $17.2 million at December 31, 2014 to $28.6 million at December 31, 2015 is not recognized as a tax expense in 2015 due to our regulatory accounting treatment of deferred taxes. Instead, the tax expense 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 account for deferred income tax expense has a balance of $28.6 million and $17.2 million at December 31, 2015 and 2014, respectively.

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

	2015	2014	2013
Federal income tax expense at statutory rate	35.00 %	35.00 %	35.00 %
State income tax expense, net of federal benefit	2.63	2.63	2.63
Patronage exclusion	(37.63)	(37.63)	(37.63)
Asset retirement obligations	(0.58)	1.40	(6.74)
Postretirement medical actuarial gains and losses	(1.09)	2.44	0.18
Various book tax differences	2.84	4.52	8.93
Regulatory treatment of deferred taxes	(1.17)	(8.36)	(2.37)
Effective tax rate	0.00 %	0.00 %	0.00 %

We had a taxable loss of $54.0 million for 2015. At December 31, 2015, we have a federal net operating loss carryforward of $406.4 million which, if not utilized, will expire between 2030 and 2035. The future reversal of existing temporary differences will more-likely-than-not enable the realization of the net operating loss carryforward. We have $3.8 million of alternative minimum tax credit carryforwards at December 31, 2015 to offset future regular taxes payable and the credit carryforwards have no expiration date.

The authoritative guidance for income taxes addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. We may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement.

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 2012 forward. We do not have any liabilities recorded for uncertain tax positions.

NOTE 8—LEASES

LESSOR—GAS TOLLING ARRANGEMENTS: We are the lessor under certain power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey the right to use power generating equipment for a stated period of time. These arrangements include sales contracts to a third party out of our J.M. Shafer, Knutson and Limon Generating Stations. Under the first of these contracts, the third party directs the use of 122 megawatts of the 272 -megawatt net generating capability of the J.M. Shafer Generating Station through June 30, 2019 under a tolling arrangement whereby the third party provides its own natural gas for generation of electricity. Under the other contracts, the third party directs the use of both of the two Knutson Generating Station units and one of the two Limon Generating Station units over the terms of the contracts under tolling arrangements whereby the third party provides its own natural gas for generation of electricity. The Limon contract was suspended for a four -year period beginning May 2009 through April 2013 and the Knutson contract was suspended for a three -year period beginning May 2010 through April 2013 to allow us to utilize the output of the turbines. Both turbine contracts resumed with the third party under the original tolling arrangements on May 1, 2013 and are in effect through April 30, 2016. We also had a similar tolling arrangement with a third party through September 30, 2014 involving one of the four 40 -megawatt units at our Pyramid Generating Station. The revenues from these operating leases of $30.1, $30.6 and $25.8 million for 2015, 2014 and 2013, respectively, are accounted for as lease revenue and are reflected in other operating revenue on the consolidated statements of operations. The generating units used in these gas tolling arrangements have a total cost and accumulated depreciation of $223 and $106 million, respectively, as of December 31, 2015, and of $232 and $108 million, respectively, as of December 31, 2014.

The minimum future lease revenues under these gas tolling arrangements at December 31, 2015 are as follows (thousands):

2016	$ 18,745
2017	11,734
2018	11,734
2019	5,867
	$ 48,080

LESSEE—GAS TOLLING ARRANGEMENT: We are the lessee under a power purchase arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time. Under this agreement, we direct the use of 70 megawatts at the Brush Generating Station for a 10-year term ending December 31, 2019 and provide our own natural gas for generation of electricity. The expense for the Brush operating lease of $5.3 million for each of the years 2015, 2014 and 2013 is included in other operating expenses on the consolidated statements of operations. Our operating lease commitments for this gas tolling arrangement at December 31, 2015 are as follows (thousands):

2016	$ 5,519
2017	5,678
2018	5,855
2019	6,031
	$ 23,083

NOTE 9—RELATED PARTIES

TRAPPER MINING, INC.: We, and certain participants in the Yampa Project, own Trapper Mining. Organized as a cooperative, Trapper Mining supplied 26, 35 and 24 percent of the coal for the Yampa Project in 2015, 2014 and 2013, respectively. Our 26.57 percent share of coal purchases from Trapper Mining was $17.7, $30.6 and $16.9 million in 2015, 2014 and 2013, respectively. Our membership interest in Trapper Mining of $14.1 and $13.7 million at December 31, 2015 and 2014, respectively, is included in investments in and advances to coal mines on the consolidated statements of financial position. Our share of Trapper Mining capital credit allocations of $531,000 for

2015, and $532,000 in each of the years 2014 and 2013 is included in capital credits from cooperatives on the consolidated statements of operations.

NOTE 10—EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,561 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan (“RS Plan”) except for the 216 employees of Colowyo Coal. 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 53-0116145 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 2015, 2014 and 2013 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 $22.9, $21.5 and $92.6 million in 2015, 2014 and 2013, respectively. Contributions in 2013 were significantly higher than those in 2015 and 2014 due to our election to exercise the prepayment option offered to participating employers in 2013.

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

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

Our contributions to the RS Plan include contributions for substantially all of the 361 bargaining unit employees that are made in accordance with collective bargaining agreements.

In 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 January 1, 2015, and over 80 percent funded at January 1, 2014, 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.

DEFINED CONTRIBUTION PLAN: We have a qualified savings plan for eligible employees who may make pre-tax and after-tax contributions totaling up to 100 percent of their eligible earnings subject to certain limitations under federal law. We make no contributions for the 361 bargaining unit employees. For all of the eligible non-bargaining unit employees, other than the 216 employees of Colowyo Coal, we contribute 1 percent of an employee's eligible earnings. For the employees of Colowyo Coal, we contribute 7 percent of an employee's eligible earnings and also match an employee's contributions up to 5 percent. We made contributions to the plan of $3.0, $2.9 and $3.0 million in 2015, 2014 and 2013, respectively.

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS: We sponsor three medical plans for all non-bargaining unit employees. 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, 2015, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles.

The postretirement medical benefit plans were amended as of December 31, 2015. The plan amendment eliminated coverage for all members after the age of 65. This did not impact the valuation as post-65 retiree contributions were sufficient to cover expected claim costs for that group, so there was no implicit subsidy to value. The postretirement medical benefit plan was amended to include three different plan options for members prior to the age of 65. This reduced the liability by approximately 11.5 percent and is reflected as a prior service cost in the amount of ($896,214) as of December 31, 2015.

The postretirement medical benefit and postemployment medical benefit obligations are determined annually by an independent actuary and are included in accumulated postretirement benefit and postemployment obligations on the consolidated statements of financial position as follows (thousands):

	2015	2014
Postretirement medical benefit obligation at beginning of year	$ 7,713	$ 2,957
Service cost	593	582
Interest cost	270	256
Plan amendments - prior service cost	(896)	—
Benefit payments (net of contributions by participants)	(325)	(276)
Actuarial (gain) loss	(632)	4,194
Postretirement medical benefit obligation at end of year	$ 6,723	$ 7,713
Postemployment medical benefit obligation at end of year	178	418
Total postretirement and postemployment medical obligations at end of year	$ 6,901	$ 8,131

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 the 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 (thousands):

	2015	2014
Actuarial gain included in accumulated other comprehensive income at beginning of year	$ (1,082)	$ 3,081
Reclassification adjustment included in income	14	31
Plan amendments - prior service cost	896	—
Actuarial gain (loss) per actuarial study	632	(4,194)
Actuarial gain (loss) included in accumulated other comprehensive income at end of year	$ 460	$ (1,082)

The assumptions used in the 2015 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	3.90 %
Initial health care cost trend (2015)	8.00 %
Ultimate health care cost trend	4.50 %
Year that the rate reached the ultimate health care cost trend rate	2025
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	12.09

Changes in the assumed health care cost trend rates would impact the accumulated postretirement medical benefit obligation and the net periodic postretirement medical benefit expense as follows (thousands):

	1% Increase	1% Decrease
Accumulated postretirement medical benefit obligation	$ 709	$ (620)
Net periodic postretirement medical benefit expense	$ 131	$ (109)

The following are the expected future benefits to be paid related to the postretirement medical benefit obligation (thousands):

2016	$ 362
2017	433
2018	473
2019	535
2020	561
2021 and thereafter	2,600
	$ 4,964

NOTE 11 – VARIABLE INTEREST ENTITIES

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

Consolidated Variable Interest Entity

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

Our consolidated statements of financial position include the Springerville Partnership's net electric plant of $853.3 and $874.4 million at December 31, 2015 and 2014, respectively, the long-term debt of $511.0 and $548.1 million at December 31, 2015 and 2014, respectively, accrued interest associated with the long-term debt of $14.3 million and $15.2 million at December 31, 2015 and 2014, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $108.8 and $109.3 million at December 31, 2015 and 2014, respectively.

Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $21.0 million for 2015 and 2014. Our consolidated statements of operations also include interest expense of $32.3 million, $34.1 million and $35.9 million for 2015, 2014, and 2013. The net losses attributable to the 49 percent noncontrolling equity interest in the Springerville Partnership are reflected on our consolidated statements of operations. The revenue associated with the Springerville Partnership lease has been eliminated in consolidation. Income, losses and cash flows of the Springerville Partnership are allocated to the general and limited partners based on their equity ownership percentages.

Unconsolidated Variable Interest Entities

Western Fuels Association: WFA is a non-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which includes us. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in WFW. We also receive coal supplies directly from WFA for the Escalante Generating Station in New Mexico and spot coal for the Springerville Unit 3 in Arizona. The pricing structure of the coal supply agreements with WFA is designed to recover the mine operating costs of the mine supplying the coal and therefore the coal sales agreements provide the financial support for the mine operations. There isn't sufficient equity at risk for WFA to finance its activities without additional financial support. Therefore, WFA is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact WFA's economic performance (acquiring and supplying fuel resources) is held by the members who are represented on the WFA board of directors whose actions require joint approval. There is shared power with a related party (Basin), which results in power and the ability to receive benefits from the significant activities of WFA. Due to Basin's participating interest of 42.27 percent interest in MBPP and ownership of the Dry Fork Station, Basin is the party most closely associated to WFA. We are not the primary beneficiary of WFA and the entity is not consolidated. Our investment in WFA, accounted for using the cost method, was $2.3 million for both December 31, 2015 and 2014, respectively, and is included in investments in other associations.

Western Fuels – Wyoming: WFW, the owner and operator of the Dry Fork Mine in Gillette, WY, was organized for the purpose of acquiring and supplying coal, through long-term coal supply agreements, to be used in the production of electric energy at the Laramie River Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by Basin). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 24.13 percent undivided interest) own the remaining 25 percent of class BB shares of WFW. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Dry Fork Mine and therefore the coal supply agreements provide the financial support for the operation of the Dry Fork Mine. There isn't sufficient equity at risk at WFW for it to finance its activities without additional financial support. Therefore, WFW is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact WFW's economic performance (which includes operations, maintenance and reclamation activities) is shared with the equity interest holders since each member has representation on the WFW board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of WFW and the entity is not consolidated.

Trapper Mining, Inc.: Trapper Mining is a cooperative organized for the purpose of mining, selling and delivering coal from the Trapper Mine to the Craig Station Units 1 and 2 through long-term coal supply agreements. Trapper Mining is jointly owned by some of the participants of the Yampa Project. We have a 26.57 percent cooperative member interest in Trapper Mining. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provide the financial support for the operation of the Trapper Mine. There isn't sufficient equity at risk for Trapper Mining to finance its activities without additional financial support. Therefore, Trapper Mining is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact Trapper Mining's economic performance (which includes operations, maintenance and reclamation activities) is shared with the cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of Trapper Mining and the entity is not consolidated. We record our investment in Trapper Mining using the equity method. Our membership interest in Trapper Mining was $14.1 million at December 31, 2015 and $13.7 million at December 31, 2014.

NOTE 12—COMMITMENTS AND CONTINGENCIES

SALES: We have delivery obligations under resource-contingent power sales contracts with Public Service Company of Colorado totaling 125 megawatts in the summer season and 175 megawatts in the winter season. These contracts expire in 2016 and 2017. We also have a resource-contingent firm power sales contract of 100 megawatts to Salt River Project Agricultural Improvement and Power District through August 31, 2036.

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under long-term contracts that expire between 2017 and 2034. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions. The projection of contractually committed purchases is based upon estimated future prices. At December 31, 2015, the annual minimum coal purchases under these contracts are as follows (thousands):

2016	$ 102,535
2017	105,457
2018	103,389
2019	104,686
2020	82,612
Thereafter	63,396
	$ 562,075

ELECTRIC POWER PURCHASE AGREEMENTS: Our principal long-term electric power purchase contracts are with Western Area Power Administration ("WAPA") and Basin. WAPA, one of four power marketing administrations of the U.S. Department of Energy, markets and supplies cost-based hydroelectric power and related services primarily to cooperatives and municipal electric systems located in 15 states in the central and western United States. WAPA markets and transmits the power to us under three contracts, one relating to WAPA's Loveland Area Project (terminates September 30, 2024), and two contracts relating to WAPA's Salt Lake City Area Integrated Projects (terminate September 30, 2024). We have entered into a new contract with WAPA relating to the Loveland Area Project which commences upon termination of the above referenced contract terminating September 30, 2024, and will run through September 2054.

Our purchases of hydroelectric-based electric power from WAPA are made at cost-based rates under long-standing federal law under which WAPA sells power to cooperatives and municipal electric systems and certain other preference customers. We utilize a portion of our electric purchases from Basin to supply power to our Nebraska members, which are primarily located east of the electrical grid separation and are generally isolated from our generating facilities that are located west of the separation. We have a contract with Basin for a term ending December 31, 2050, to supply the electrical requirements of its Nebraska members in excess of power supplied by WAPA. We also purchase 225 MWs from Basin for use west of the electrical separation under a contract for a term ending December 31, 2050.

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

	2015	2014	2013
WAPA	$ 89,986	$ 91,639	$ 91,038
Basin	127,500	132,649	136,223

ENVIRONMENTAL: Our electric generation facilities are subject to various operating permits and must operate within guidelines imposed by numerous environmental regulations. We believe these facilities are currently in compliance with such regulatory and operating permit requirements.

LEGAL: On October 19, 2012, we gave notice, as required by New Mexico law, to the New Mexico Public Regulation Commission ("NMPRC") of our new A-37 wholesale rate which was scheduled to become effective on January 1, 2013. The rate would have increased revenue collected from all 44 of our Members by approximately 4.9 percent, with revenues from our 12 New Mexico Members increasing by approximately 6.7 percent. In November 2012, three of our Members located in New Mexico filed protests of our rates with the NMPRC. On December 20, 2012, the NMPRC suspended the rate filing in New Mexico and appointed a hearing examiner to conduct a hearing and establish reasonable rate schedules pursuant to New Mexico law. On June 25, 2013, we filed to withdraw the A-37 rate. On July 3, 2013, the NMPRC denied the filing to withdraw and ordered the A-37 rate filing to be consolidated with the A-38 rate filing described below. On September 10, 2013, we gave notice, as required by New Mexico law, to the NMPRC of our new A-38 wholesale rate which was scheduled to become effective on January 1, 2014. The A-38 rate modified the rate design but did not increase the general revenue requirement. On December 11, 2013, the NMPRC suspended the A-38 rate filing and assigned the consolidated A-37 and A-38 rate filings to a hearing examiner. In August 2014, we and the New Mexico Members executed a preliminary mediation agreement providing for a temporary rate rider through no later than December 31, 2015 (unless terminated earlier as provided in the preliminary mediation agreement) and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. We filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider was applied in conjunction with the 2012 wholesale rate to recover additional revenue from the New Mexico Members in an annualized amount of $7 million per year, which was prorated beginning October 2 for 2014. In 2015 and 2014, the overall revenue impact of the New Mexico Members paying a lower rate was approximately $10.7 million and $16.4 million, respectively. On October 9, 2015, we gave notice, as required by New Mexico law, to the NMPRC of our 2016 wholesale rate, or the A-39 rate. No New Mexico Member filed a protest with the NMPRC of the A-39 rate and thus the A-39 rate became effective on January 1, 2016 without NMPRC review or approval. On December 9, 2015, we and the New Mexico Members filed a joint motion with the NMPRC seeking continuation of the suspension of the procedural schedule related to the rate protests to allow the parties additional time to proceed with further negotiations towards a global settlement. On January 7, 2016, the NMPRC ordered that the procedural schedule related to the rate protests remains suspended until further order of the NMPRC. As part of the global settlement, the parties seek to address the issue of our rate regulation in New Mexico, payment of capital credits, and whether we have the right to collect the amounts uncollected from our New Mexico Members as a result of the suspension of prior rate filings. We cannot predict the outcome of this matter or if a global settlement will be reached, although we do not believe this proceeding is likely to have a material adverse effect on our financial condition or our future results of operations or cash flows.

On March 4, 2013, three of our Colorado Members and several of their large industrial customers filed a complaint at the Colorado Public Utilities Commission ("COPUC") alleging that our A-37 rate design was unjust and unreasonable. On April 4, 2013, we filed a motion to dismiss the complaint arguing lack of jurisdiction by the COPUC over our wholesale rates. The COPUC assigned the matter to an Administrative Law Judge ("ALJ"). The ALJ bifurcated the case into deciding first, whether the COPUC had the jurisdiction to hear such a case against us, who has been historically regulated by its membership through its Board, and secondly to hear the facts in the case depending on jurisdiction. The ALJ conducted a hearing in July 2013 and ruled on September 11, 2013 denying our motion to dismiss. In October 2013, we appealed the ALJ's decision to the full commission and on December 18, 2013, the commission granted in part and denied in part our motion contesting the ALJ's decision and remanded the case to the ALJ to hold a hearing on limited issues. In November 2014, we and the three Colorado Members executed a preliminary agreement providing for a temporary optional rate effective December 1, 2014 and to continue through no later than December 31, 2015, available to all non-New Mexico Members and a suspension of the procedural schedule related to the complaint. The ALJ entered a decision on November 28, 2014 holding this matter in abeyance until December 31, 2015 to give the parties time to work toward a global settlement and permanent rate. On December 28, 2015, we and the three Colorado Members filed a joint motion with the COPUC to withdraw the complaint and dismiss the proceeding. On January 19, 2016, the ALJ granted our joint motion to withdraw the complaint, dismiss the proceeding with prejudice and close the proceeding. The ALJ's order has become effective by operation of law.

The Purchase Option and Development Agreement was executed on July 26, 2007 between us and Sunflower Electric Power Corporation ("Sunflower") and other Sunflower parties. The agreement calls for us to make option payments totaling $55 million to Sunflower and/or the other Sunflower parties in exchange for the development rights to develop a new coal-fired generating unit or units at Sunflower's existing single-unit Holcomb Station in western Kansas. Upon execution, $25 million was paid. In 2008, $5 million was paid and the remainder will be paid on the purchase date. The purchase date will be designated by us, Sunflower and the other parties to the Purchase Option and Development Agreement after we exercise our option to acquire the development rights. The purchase date cannot currently be estimated due to legal uncertainties surrounding the status of the necessary air permits. The original air permit application was denied by the Kansas Department of Health and Environment ("KDHE") in October 2007 and we and Sunflower appealed the denial to the Kansas courts. Subsequent to the denial of the air permit, Sunflower entered into an agreement with the governor of Kansas that could result in the KDHE issuing a permit for one new coal-fired generating unit at Holcomb Station of 895 megawatts. As a result of the agreement, Sunflower and we withdrew the appeal of the denial of the original air permit application. The KDHE issued the new permit on December 16, 2010. The Sierra Club filed an appeal of the new permit with the Kansas Court of Appeals on January 14, 2011 and the case was immediately transferred to the Kansas Supreme Court. The Kansas Supreme Court remanded the permit to the KDHE to consider a limited issue. The KDHE issued an addendum to the permit on May 30, 2014. The Sierra Club filed an appeal with the Kansas Court of Appeals on June 27, 2014. On November 3, 2014, the Kansas Supreme Court granted a pending motion to transfer the case from the Court of Appeals and KDHE subsequently filed the record on appeal. The Kansas Supreme Court heard oral argument on the appeal on January 28, 2016. Excluding the cost of land and water rights, the cost of developing the units incurred by us as of December 31, 2015 is $86.7 million, which is included in other deferred charges on the consolidated statements of financial position. We are unable to project the ultimate outcome of this matter or when the air permit application process may conclude.

In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five days in northern New Mexico, primarily on national forest service land in the Santa Fe National Forest. Six plaintiff groups, comprised of property owners in the area of the Las Conchas Fire, filed separate lawsuits against our Member, Jemez Mountains Electric Cooperative, Inc. ("JMEC") in the Thirteenth District Court, Sandoval County in the State of New Mexico. Plaintiffs alleged that the fire ignited when a tree growing outside the right of way fell onto a distribution line owned by JMEC as a result of high winds. On January 7, 2014, the district court allowed all parties and related parties to amend their complaints to include the addition of us as a party defendant. The allegations in each case were similar. Plaintiffs alleged that we owed them independent duties to inspect and maintain the right-of-way for JMEC's distribution line and that we are also jointly liable for any negligence by JMEC under joint venture and alter ego theories. On June 16, 2014, we filed multiple motions for summary judgment including for plaintiffs' claims related to nuisance, trespass, negligence per se, independent duty, joint venture and alter ego. On December 29, 2014, we received a demand letter from the U.S. Department of Justice for costs incurred as a result of the fire, also alleging the joint venture theory. JMEC has settled with the subrogated insurers, executing and funding the deal on December 30, 2014 and on February 7, 2015, the district court dismissed the subrogated insurers' claims against us with prejudice. Settlement demands were received from plaintiffs Jemez Pueblo and Pueblo de Cochiti claiming damages in the amount of approximately $34.4 million and $23.9 million, respectively, focusing mainly on damages arising from flooding subsequent to the fire. On March 9, 2015, the district court granted our motions for summary judgment related to nuisance, trespass, negligence per se, and alter ego, but denied our motions related to independent duty and joint venture. On March 17, 2015, we filed an application for interlocutory appeal with the New Mexico Court of Appeals related to the district court's denial of our motions for summary judgment for plaintiffs' claims related to independent duty and joint venture. The New Mexico Court of Appeals denied our application for interlocutory appeal on May 27, 2015. A jury trial commenced on September 28,

2015. On October 28, 2015, the jury affirmed our position that we and JMEC did not operate as a joint venture or joint enterprise. The jury did find we owed the plaintiffs an independent duty and allocated comparative negligence with JMEC 75 percent negligent, us 20 percent negligent, and the United States Forest Service 5 percent negligent. On November 11, 2015, we filed a request with the district court to certify for interlocutory appeal certain issues regarding our duty under a negligence claim, which was denied by the district court in January 2016. Three or four separate trials will occur in the second half of 2016 and first quarter of 2017 to determine the amount of damages. We maintain $100 million in liability insurance coverage for this matter. Although we cannot predict the outcome of these matters at this point in time, we do not expect them to have a material adverse effect on our financial condition or our future results of operations or cash flows.

In May 2013, near the Village of Pecos, New Mexico, a wildfire known as the Tres Lagunas Fire was ignited and subsequently destroyed timber on thousands of acres and burned for approximately three weeks. On March 25, 2014, a lawsuit was filed by David Old d/b/a Old Wood, The Viveash Ranch, and River Bend Ranch, LLC, against our Member, Mora-San Miguel Electric Cooperative, Inc. ("MSMEC"), in the First Judicial District Court for the County of Santa Fe, New Mexico. In the complaint, plaintiffs allege that the Tres Lagunas Fire resulted from wind blowing a portion of a dead standing tree into an electric distribution power line owned and operated by MSMEC. On November 6, 2015, plaintiffs filed a motion to amend their complaint and include the addition of us as a defendant. The district court approved the motion to amend on November 20, 2015 and plaintiffs' first amended complaint was filed. Plaintiffs assert claims of negligence, violations of New Mexico's Unfair Practices Act ("NMUPA"), and strict liability. On December 21, 2015, we filed a motion to dismiss the NMUPA and strict liability claims and, additionally, filed our answer and 12-person jury demand. In 2014, we renewed our coverage and now maintain $200 million in liability insurance coverage for this matter. Although we cannot predict the outcome of this matter at this point in time, we do not expect it to have a material adverse effect on our financial condition or our future results of operations or cash flows.

NOTE 13—QUARTERLY FINANCIAL DATA (UNAUDITED)

Unaudited operating results by quarter for 2015 and 2014 are presented below. In the opinion of management, all adjustments (consisting of normal recurring accruals) necessary for the fair statement of the results of operations for such periods have been included:

Statement of Operations Data (thousands):	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2015					
Operating revenues	$ 328,391	$ 305,913	$ 388,102	$ 313,042	$ 1,335,448
Operating margins	49,384	38,550	81,412	8,623	177,969
Net margins attributable to the Association	20,126	6,284	48,302	(21,299)	53,413
2014					
Operating revenues	$ 349,198	$ 327,288	$ 396,479	$ 322,126	$ 1,395,091
Operating margins	53,652	34,098	69,603	24,524	181,877
Net margins attributable to the Association	24,511	3,373	40,451	(4,099)	64,236

Our business is influenced by seasonal weather conditions, changes in rates and other factors. In the fourth quarter of 2015, net margins were negative primarily due to increased depreciation and amortization expense resulting from renewed right-of-way easements, and the completion of capital projects and putting them into service. Fuel expense increased due to increased generation and increased coal costs due to higher per ton mine production costs. Net margins in the fourth quarter of 2014 were lower primarily due to decreased non-member electric sales and increased production expense resulting from scheduled maintenance outages at our coal-fired generating stations.

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