Great River Energy respectfully files this Integrated Resource Plan with the Minnesota Public Utilities Commission and invites the Commission to review and accept our resource plan filing and support our conclusion it is in the best interest of our membership.

As a cooperative, Great River Energy’s resource decisions are ultimately determined by our board of directors, which is elected from our membership. We carefully consider input from the Commission and other stakeholders before, during and following the preparation of our Integrated Resource Plan filings. Stakeholder engagement leading up to this filing has fostered mutual understanding between Great River Energy, our member-owner cooperatives and others interested in our resource portfolio.

The resource decisions we face today are far different from those a decade ago. At that time, the Midwest energy market included 1,000 megawatts of wind generation — today, there are 15,000 megawatts. Wind energy has become the new “base load” source of electricity, supplanting coal as the resource to which all others must adapt.

The rise of wind has presented opportunities for Great River Energy. We have announced plans for an additional 400 megawatts of favorably priced wind energy, which will bring our total renewable energy capacity to more than 1,000 megawatts by 2021, including 200 megawatts of hydropower.

Variable resources in the energy market have driven innovation. Our engineers and operators have modified our largest power plant, Coal Creek Station, to better adjust its output in response to market signals.

Market forces have also prompted difficult decisions. Great River Energy is retiring Stanton Station because it is no longer economical to operate in today’s energy market.

As the electric system has become more efficient, there is growing support to use electricity in new ways. Encouraging the smart use of electricity, or “environmentally beneficial electrification,” will improve the way we serve our members.

We continue to offer our Revolt program, which allows electric vehicle drivers to charge their cars entirely with wind energy at no added cost. Revolt has advanced our knowledge of electric transportation and spurred research into new and exciting opportunities, such as electric school buses and forklifts.

We are working with our members to attract economic development opportunities through financial support and unique energy solutions. We are leading the charge on community energy storage, which employs common household appliances to provide critical services the electric grid needs.
Electrification initiatives provide our members with relief from financial pressure due to declining electricity sales. They also build member engagement by helping home- and business-owners save money and improve efficiency.

This Integrated Resource Plan provides a comprehensive view of our vision, initiatives, future resource plan, and implementation actions to best serve the needs of our members. It aligns with Great River Energy’s mission to provide our members with affordable, reliable energy in harmony with a sustainable environment. This resource plan positions us to best serve our members now and into the future.

David Saggau  
President and CEO
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1 Non-Technical Summary

This Integrated Resource Plan (IRP) provides a comprehensive view of Great River Energy’s (GRE) resource plan over the next 15 years. The plan represents our intent to reliably meet our members’ energy needs in a cost-effective and environmentally responsible manner. The plan is similar in many ways to our 2014 IRP, with improvements in market analysis and modeling. We also describe more recent innovative initiatives, such as our collaborations with our members on distributed energy resources. Like the 2014 IRP, the plan continues to meet our members’ needs and to innovate, collaborate and lead to competitively power the future.

Over the planning period, GRE is well-positioned to meet our members’ future power supply needs while we continue to adapt to a changing industry. Our forecasts of demand and energy reflect growth that is below historical growth, but comparable to more recent growth. We expect a compounded annual growth rate of 1.3 percent in energy, and a growth rate of 1.0 percent in demand. Our preferred expansion plan (Preferred Plan) builds on changes in our resource portfolio that have already significantly reduced carbon emissions. The only resource additions in our Preferred Plan are wind resources, and the majority of the added wind resources are toward the end of the planning period.

This IRP provides our vision, initiatives, future resource plan, and implementation actions. It aligns with our mission to provide our members with affordable, reliable energy in harmony with a sustainable environment.
The IRP meets the five factors to consider in Integrated Resource Plans as set forth in Minnesota Rules.

### 1.1 Great River Energy Overview

GRE is a not-for-profit electric generation and transmission (G&T) cooperative serving the needs of our 28 member electric distribution cooperatives (members). We generate and transmit electricity for our members, who are located throughout the state of Minnesota and into northwestern Wisconsin. Our members range geographically across Minnesota from the suburbs of the Twin Cities, to the Arrowhead region in northern Minnesota, to farming communities in the far southwest corner of the state. Our members serve a total of 685,000 end-use consumers, representing about 1.7 million people. In terms of energy sales, our system-wide load characteristics are 56 percent residential, two percent seasonal, and 42 percent commercial and industrial.

GRE owns and maintains $4 billion in assets that include 11 power generating plants and nearly 4,800 miles of transmission lines. We are the second largest power supplier in Minnesota by peak demand and the fourth largest G&T cooperative in the country by assets. We provide our members with a diverse energy supply fuel mix, including coal, refuse-derived fuel (RDF), hydroelectric, natural gas, fuel oil, biogas, wind and solar sources. We thoughtfully design and maintain a portfolio of generation resources and transmission resources to provide reliable and affordable wholesale electricity to our members. Our generation resources, both owned and contracted through power purchase agreements (PPA), are of varying sizes, locations and fuels with each serving to add value to our resource portfolio. Our transmission lines and substations are designed to reliably deliver electricity where and when needed.
1.2 Vision and Mission

GRE continues to operate in an environment of change in the energy industry. Our vision is: “Innovate, collaborate and lead to competitively power the future.” It is important to GRE and our members that we continue to reinforce our triple bottom line of affordable rates, reliable energy and environmental stewardship. Our mission is derived directly from these principles, and is to provide our members with affordable, reliable energy in harmony with a sustainable environment.

Consistent with our vision and mission, GRE’s resource portfolio continues to transition to the future, while providing our members with reliable and affordable rates in a manner that minimizes environmental impact. We have taken action, and continue to prepare for, future environmental regulations and market conditions. We are retiring Stanton Station, implementing more flexible operations at Coal Creek Station, making changes to the fuel mix at Spiritwood Station, and procuring new renewable energy for our members.

This IRP draws on our vision and mission, giving us a path forward that best meets our members’ needs in a changing environment.

1.3 Our Members

As a cooperative, GRE’s members are our customers. Cooperatives provide services to their members on a not-for-profit basis. Cooperatives meet members’ collective needs more effectively than if each member acted independently. Cooperatives are governed by a board of directors elected from the membership, which sets policies and procedures that are implemented by the cooperative’s management.
GRE provides services to two types of members: All Requirements (AR) members and Fixed Obligation (Fixed) members. The 20 AR members purchase all of their power and energy requirements from us, subject to limited exceptions. For instance, the AR members have the option to self-supply up to five percent of their power and energy requirements from renewable resources. The eight Fixed members purchase a fixed portion of their power and energy requirements from us, and purchase all supplemental requirements from an alternate power supplier. Table 1 below provides the names, types and headquarters locations of our members:

Table 1 - GRE Members and Locations

<table>
<thead>
<tr>
<th>Member</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agralite Electric Cooperative (Fixed)</td>
<td>Benson, Minn.</td>
</tr>
<tr>
<td>Arrowhead Electric Cooperative, Inc. (AR)</td>
<td>Lutsen, Minn.</td>
</tr>
<tr>
<td>BENCH Electric Cooperative (AR)</td>
<td>Mankato, Minn.</td>
</tr>
<tr>
<td>Brown County Rural Electric Association (AR)</td>
<td>Sleepy Eye, Minn.</td>
</tr>
<tr>
<td>Connexus Energy (AR)</td>
<td>Ramsey, Minn.</td>
</tr>
<tr>
<td>Cooperative Light &amp; Power (AR)</td>
<td>Two Harbors, Minn.</td>
</tr>
<tr>
<td>Crow Wing Power (Fixed)</td>
<td>Brainerd, Minn.</td>
</tr>
<tr>
<td>Dakota Electric Association (AR)</td>
<td>Farmington, Minn.</td>
</tr>
<tr>
<td>East Central Energy (AR)</td>
<td>Braham, Minn.</td>
</tr>
<tr>
<td>Federated Rural Electric Association (Fixed)</td>
<td>Jackson, Minn.</td>
</tr>
<tr>
<td>Goodhue County Cooperative Electric (AR)</td>
<td>Zumbrota, Minn.</td>
</tr>
<tr>
<td>Itasca-Mantrap Cooperative Electrical Association (AR)</td>
<td>Park Rapids, Minn.</td>
</tr>
<tr>
<td>Kandiyohi Power Cooperative (AR)</td>
<td>Spicer, Minn.</td>
</tr>
<tr>
<td>Lake Country Power (AR)</td>
<td>Grand Rapids, Minn.</td>
</tr>
<tr>
<td>Lake Region Electric Cooperative (AR)</td>
<td>Pelican Rapids, Minn.</td>
</tr>
<tr>
<td>McLeod Cooperative Power Association (AR)</td>
<td>Glencoe, Minn.</td>
</tr>
<tr>
<td>Meeker Cooperative Light &amp; Power Association (Fixed)</td>
<td>Litchfield, Minn.</td>
</tr>
<tr>
<td>Mille Lacs Energy Cooperative (AR)</td>
<td>Aitkin, Minn.</td>
</tr>
<tr>
<td>Member</td>
<td>Location</td>
</tr>
<tr>
<td>-----------------------------------------------------------------------</td>
<td>---------------------</td>
</tr>
<tr>
<td>Minnesota Valley Electric Cooperative (Fixed)</td>
<td>Jordan, Minn.</td>
</tr>
<tr>
<td>Nobles Cooperative Electric (AR)</td>
<td>Worthington, Minn.</td>
</tr>
<tr>
<td>North Itasca Electric Cooperative, Inc. (AR)</td>
<td>Bigfork, Minn.</td>
</tr>
<tr>
<td>Redwood Electric Cooperative (Fixed)</td>
<td>Clements, Minn.</td>
</tr>
<tr>
<td>Runestone Electric Association (AR)</td>
<td>Alexandria, Minn.</td>
</tr>
<tr>
<td>South Central Electric Association (Fixed)</td>
<td>Saint James, Minn.</td>
</tr>
<tr>
<td>Stearns Electric Association (AR)</td>
<td>Melrose, Minn.</td>
</tr>
<tr>
<td>Steele-Waseca Cooperative Electric (AR)</td>
<td>Owatonna, Minn.</td>
</tr>
<tr>
<td>Todd-Wadena Electric Cooperative (AR)</td>
<td>Wadena, Minn.</td>
</tr>
<tr>
<td>Wright-Hennepin Cooperative Electric Association (Fixed)</td>
<td>Rockford, Minn.</td>
</tr>
</tbody>
</table>

As a cooperative, GRE has a democratic governance structure. We are governed by a board of directors that includes 24 directors, each of whom is a member of the board of directors of one of our members. Our members are governed by their boards of directors that are elected by their member-consumers.

GRE’s members provide direction and oversight at many levels, and work with GRE through regular meetings with member leaders, regional meetings and member staff working groups.

### 1.4 Generation Resources

GRE’s generation resources include 11 power plants and purchased power from several wind farms and other generating facilities, resulting in more than 3,300 MW of generation capability. Our resource portfolio is a diverse mix of coal, refuse-derived fuel (RDF), hydroelectric, natural gas, fuel oil, biogas, wind and solar sources.
GRE owns two generating stations that are located in North Dakota (N.D.): Coal Creek Station, located near Underwood, N.D., and Spiritwood Station located in Jamestown, N.D. Coal Creek Station is a 1,146 megawatt (MW) coal-fired generating station. Its two units went into commercial operation in 1979 and 1980. Spiritwood Station is a 99 MW combined heat and power (CHP) coal-fired generating station that went into commercial operation in 2014, and is also capable of operating on a combination of natural gas and coal. Both Coal Creek Station and Spiritwood Station operate on lignite coal that is processed with GRE’s proprietary DryFine™ technology. The innovative technology reduces moisture and refines lignite coal, increasing the efficiency and performance of the fuel while reducing emissions.

GRE’s peaking resources, which consist primarily of combustion turbines, provide a needed capacity and resource adequacy in our resource portfolio. The primarily natural gas fired peaking units supply a small amount of our energy at historically one to five percent of our total annual energy production. We have 1,300 MW of gas peaking generation in our resource portfolio, all located in Minnesota.

GRE processes municipal waste into RDF and uses the fuel to generate energy at our 31 MW Elk River Energy Recovery Station. We also purchase energy from a 3.2 MW landfill gas generator in Elk River and from a dairy farm with anaerobic digester projects.

We installed a 200 kilowatt (kW) wind generator and a 72 kW solar photovoltaic system at our headquarters office in Maple Grove, Minn., when the building was constructed in 2006. In 2014, we installed an additional 250 kW of solar generation at our headquarters, utilizing three solar generation technologies. GRE and our members have installed and signed purchase
agreements for more than five megawatts of solar generation. The members also purchase energy from other distributed generation projects connected to their distribution systems, including dairy farm anaerobic digester facilities, small wind and photovoltaic generators.

Figures 1 and 2 indicate our 2016 generation portfolio capacity by fuel type, and energy production by fuel type, respectively. This information includes the annual energy and capacity of our 189 MW coal fired Stanton Station plant, which is planned to retire on May 1, 2017.

Our generation resources are located in Minnesota and North Dakota. We have procured wind through power purchase agreements in Minnesota, North Dakota and Iowa. Our solar facilities and our members’ solar facilities are all in Minnesota.
Figure 3 shows the location of GRE’s generating resources. Due to Stanton Station’s 2017 retirement date, it is not included in Figure 3.

We continue to add renewable resources to our portfolio. In 2017, we concluded a new power purchase agreement (PPA) for 300 MW of new wind resources beginning in 2020. Additionally, we negotiated an additional 100 MW wind PPA beginning in 2021. These new PPAs will bring the amount of wind generation in our portfolio to 768 MW nameplate capacity by 2021.

After the retirement of Stanton Station in 2017, our portfolio will reflect more natural gas-fired capacity than coal-fired capacity for the first time in our history. Additionally, when considering our existing 200 MW agreement with Manitoba Hydro, nearly 30 percent of our energy generation will come from wind and hydro beginning in 2021.
1.5 Transmission

Minnesota’s electric transmission system—the high voltage power lines that transmit electricity from power generation facilities to customers—is part of an overall regional transmission grid operated in coordination with other systems through the Upper Midwest and Eastern United States.

GRE’s transmission system is a part of this larger system. We own almost 4,800 miles of transmission lines that deliver electricity to our 28 members. The voltage and mileage of transmission lines and the number of substations owned or partially owned by GRE are shown in Table 2.

Table 2 - Great River Energy Transmission Assets

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Mileage</th>
</tr>
</thead>
<tbody>
<tr>
<td>69 kilovolt (kV) or less</td>
<td>3,093</td>
</tr>
<tr>
<td>115kV</td>
<td>528</td>
</tr>
<tr>
<td>161 kV</td>
<td>46</td>
</tr>
<tr>
<td>230 kV</td>
<td>524</td>
</tr>
<tr>
<td>345 kV</td>
<td>75</td>
</tr>
<tr>
<td>500 kV</td>
<td>70</td>
</tr>
<tr>
<td><strong>Total AC Transmission</strong></td>
<td><strong>4,336</strong></td>
</tr>
<tr>
<td>+/- 400kW DC</td>
<td>436</td>
</tr>
<tr>
<td><strong>Total Transmission Line</strong></td>
<td><strong>4,772</strong></td>
</tr>
<tr>
<td><strong>Total Transmission Substations</strong></td>
<td>101</td>
</tr>
<tr>
<td>* Does not include lines partially owned by Great River Energy</td>
<td></td>
</tr>
</tbody>
</table>

Due to intersecting service territories, many of our members’ loads are interconnected to transmission facilities owned by neighboring utilities. GRE and the interconnected utilities have turned over functional control of their respective transmission systems to the Midcontinent Independent System
Operator, Inc. (MISO). We jointly plan, build, operate, and maintain transmission facilities to ensure that the most efficient and cost-effective lines are available to provide reliable service at reasonable rates for our members.

We were a founding member of and participant in the CapX2020 initiative with other utilities in the region to plan, develop and construct new regional-scale transmission facilities. CapX2020 planned and constructed four large projects of approximately 700 line miles mainly in Minnesota. The CapX2020 lines improve reliability, provide additional outlet capability for new generation, and reduce congestion. The four projects went into service between 2011 and 2016. GRE invested in three of the projects: the Bemidji, Minn. - Grand Rapids, Minn. 230 kV project; the Brookings County, S.D. – Hampton, Minn. 345 kV project; and the Fargo, N.D. – Monticello, Minn. 345 kV project.

We continue to participate in the CapX2020 initiative. CapX2020 is engaged in state and regional transmission planning and policy initiatives.

1.6 Portfolio Changes since the Last IRP Filing

GRE’s portfolio continues to evolve in response to changes in the industry and the market. Some of the steps that we have taken to transition our portfolio include:

- We completed negotiations with Dairyland Power Cooperative to terminate our purchase obligation for 50 percent of the capacity and energy from Genoa 3, a 379 MW coal-fired power plant in southwestern Wisconsin.
- We plan to retire Stanton Station in 2017. The decision to retire the plant was driven primarily by market economics. It has become increasingly
difficult to operate the plant economically with the continued low market prices that are expected to continue into the future.

- We began utilizing natural gas combined with coal at Spiritwood Station, lowering fuel costs and reducing carbon dioxide emissions.

- We are altering the role of Coal Creek Station in the MISO market by reducing minimum output requirements. This change is in response to market price fluctuations. We are also improving Coal Creek Station’s ramping capabilities. These changes will help the units continue to operate efficiently and cost effectively, especially as wind generation increases in the region. These changes are expected to also result in lower carbon dioxide emissions.

- We added 250 kW of solar energy at our Maple Grove headquarters building and our members have added nearly five megawatts of solar resources throughout their service areas.

- We executed a new 300 MW wind PPA that will begin in 2020. This project is located in south central North Dakota and will provide enough clean energy to our portfolio to power 120,000 homes.

- We came to agreement on a new 100 MW wind PPA that will begin in 2021 located in southwestern Minnesota that will provide energy beginning in 2021, enough energy to power 40,000 homes.

- Our members, with our support, are increasing development of distributed energy resources in their service territories. Our AR members have added nearly two megawatts of renewable energy in their service territories as part of a five percent member option. Several more megawatts of distributed solar resources are currently in development or under consideration.
1.7 Load and capability position

In GRE’s resource planning process, the load and energy requirements of our members must be met while also meeting MISO’s Resource Adequacy requirements. Under our Preferred Plan (described below), we will meet our load requirement and MISO’s additional Planning Reserve Margin Requirement (PRMR) over the 15 year planning period. Figure 4 below shows our projected load and capability through the planning period inclusive of the resource additions in the Preferred Plan.

Figure 4 - Load and Capability Position with Preferred Plan

1.8 The Preferred Plan

Our Preferred Plan includes the Five Year Action Plan described below and adds 600 MW of wind resources beginning in 2029. Our Preferred Plan is summarized in Table 3. The Preferred Plan does not include any new fossil fuel-based generation during the planning period.
GRE has developed a Preferred Plan that is low cost, reliable and provides options to manage our generation fleet in a potentially carbon-constrained future. The Preferred Plan provides flexibility to respond to market trends and transitions in the energy industry. It provides a hedge to market price exposure and focuses on our mission, vision and triple bottom line.

We have taken steps to implement the Preferred Plan. We recently executed an agreement for the addition of 300 MW of new wind resources beginning in 2020. We have also come to agreement on an additional 100 MW of wind in 2021. The only other resources additions are wind resources planned for late in the planning period. Other than Stanton Station, we do not plan to retire any resources during the planning period.

Table 3 – GRE’s Preferred Plan

<table>
<thead>
<tr>
<th>Resource Plan (MW) Based on Nameplate Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year</strong></td>
</tr>
<tr>
<td>2017</td>
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<tr>
<td>2018</td>
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<td>2019</td>
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<tr>
<td>2031</td>
</tr>
<tr>
<td>2032</td>
</tr>
</tbody>
</table>
1.9 Five Year Action Plan

Our Five Year Action Plan is to:

- Retire Stanton Station.
- Continue to operate all other owned generation units.
- Increase the flexibility of Coal Creek Station operations.
- Continue implementing cost-effective opportunities at our facilities to lower emissions and provide greater customer value through efficiency improvements.
- Continue to co-fire natural gas at Spiritwood Station when economic.
- Add 300 MW of wind beginning in 2020.
- Add 100 MW of wind beginning in 2021.
- Continue our demand-side management and demand response initiatives.
- Continue engagement with our members on grid modernization initiatives.
- Encourage environmentally beneficial electrification initiatives.
- Comply with all environmental and regulatory requirements.
- Continue our energy policy discussions with our members, state, regional, MISO, regulatory, and national energy groups to help shape our future.
- Continue to work with our members in implementing distributed energy resources.
- Ultimately, to serve our members with low cost, reliable and environmentally responsible power.
1.10 Innovative Initiatives

GRE and our members are continually engaged in innovative initiatives to manage costs, reliability and environmental stewardship, and adapt to changes in the energy industry. We are engaged with several new programs which are helping us to learn more about the changing technologies and consumer preferences.

GRE and our members are developing distributed energy resources. In addition to GRE-developed renewable resources, our AR members are entitled to undertake renewable energy development projects on their own, up to a maximum of five percent of their energy requirements. We refer to such member-owned facilities and power purchase agreements as Member Renewable Resources. Member Renewable Resources are sometimes dedicated to community solar offerings, remain as wholesale renewable resources, or utilized as a combination of the two.

We support our members in developing these local Member Renewable Resources. Our AR members have 11 community solar projects installed throughout their service areas and more in development. These projects are in addition to the 650 kW of solar projects that GRE has installed at our headquarters office in Maple Grove and at the offices of 19 of our AR members, and the 2.25 MW Dickinson Solar Project, a resource dedicated to Wright-Hennepin Cooperative Electric Association, one of the largest cooperative developed solar installations in the state.

Our members, with our support, are increasing development of distributed energy resources in their service territories. Our AR members have added nearly two megawatts of Member Renewable Resources in their service territories as part of the five percent option. Several more megawatts of
distributed solar resources are currently in development and under consideration.

We have taken significant steps to transition our portfolio to lower greenhouse gas emitting resources. We have reduced our carbon emissions 27 percent across our generation fleet since 2005.

We are engaged with our members in grid modernization, an effort to identify new and growing technologies that will impact the transmission and distribution systems. We plan to implement pilot programs around those technologies with our members. We are also facilitating carbon emission reductions by supporting electric vehicles (EV) and supporting an electric school bus fuel conversion from diesel to electricity.

We are working with our members on electric thermal storage, a program which allows us to creatively store energy in water heaters owned by our members’ end users. We continue to work with our members on economic development to encourage the growth and health of their communities.

1.11 Environmental Update

GRE’s goal is full compliance with all applicable environmental regulations and is preparing to comply with all expected future regulations. Consistent with our triple bottom line, GRE has worked hard to reduce the environmental impact of our business operations. Between 2005 and 2015, we achieved the following emission reductions across our generation fleet:

1. Carbon dioxide (CO₂) emissions in our generation portfolio have decreased by 27 percent;
2. Total sulfur dioxide (SO₂) emissions have decreased by 61 percent; and

3. Total nitrogen oxides (NOx) emissions have decreased by 49 percent.

We continue to enhance our environmental stewardship by adding renewable resources to our portfolio, operating our facilities in accordance with ISO 14001 registered environmental management systems, investing in emission controls, and developing commercial uses for our facilities’ byproducts.

1.12 Current Market Outlook

The MISO market plays an important role in our decision making. The energy that serves our members’ needs is purchased directly from the market, not from a particular generating station. The energy that our generation resources produce is sold directly into the market, not to a particular customer. Market prices have a direct influence on our decisions about generation resources.

The current low market prices in the Upper Midwest are expected to continue into the future, driven by the significant amount of wind generation in our region and by the availability and price of low cost natural gas. We evaluate how our generation resources perform in the market, and explore ways to increase the overall efficiency of our generation portfolio of resources in the market. Examples include our decision to retire Stanton Station by May 1, 2017, and to add natural gas co-firing capability at Spiritwood Station. Other examples include our conservation and demand response programs, and our electrification of the economy initiatives.
1.13 Energy Efficiency

GRE’s portfolio of energy efficiency program offerings is informed by the end uses that are served by our members. Our members’ end-uses are dominated by residential use. As a percentage of total member end-use accounts, more than 80 percent are residential. However, a significant percentage of our members’ overall energy savings achievements are realized by large commercial, industrial and agricultural end users.

Since 2010, GRE’s members have realized aggregate results that are in excess of the 1.0 percent demand-side energy conservation goals that have been set by the Minnesota Legislature, as shown in Figure 5 below. The bars represent kilowatt-hour (kWh) savings achievements while the red line represents percent achievement by year. The blue line represents the Minnesota demand-side savings percent goal.

Figure 5 - GRE Member Cooperative Energy Savings Achievements 2008-2015
GRE is committed to working with our members and their end users to build on the demonstrated success of our historic energy savings programs. Our ongoing efforts during the 15-year planning period will continue to evolve and develop this resource. We plan to continue to achieve total savings results equal to 1.5 percent of total retail energy savings in each year of the planning period. We intend to accomplish this by continuing to drive energy savings equivalent to 1.0 percent through member-side activities, while obtaining energy efficiency savings equivalent to 0.5 percent from investments in supply-side efficiency throughout our members’ systems.

1.14 Demand Response

Since 1979, GRE and our members have saved millions of dollars from joint investment in demand response initiatives. As the years go by the dollars saved from demand response investments continues to accumulate. The value of demand response is increasing, as development of the wholesale power market combined with advancements in demand response technologies allow us to provide more value from demand response resources than what was previously possible.

Historically, utilities engaged in demand response activities to reduce peak demand. That method of controlling resources is typically referred to as peak shaving. Peak shaving still plays an important role in the overall value of demand response. However, moving forward, GRE will be focusing more of our demand response efforts on controlling for energy pricing, integrating demand response into transmission planning considerations and enabling ancillary service functions.
Our members currently have almost 400 MW of demand response control on our system. This is more than 15 percent of our system peak load requirements. Depending on the season, the end uses that are involved in our demand response programs are peak shave water heating, irrigation, cycled air conditioning, and commercial and industrial interruptible load. The overall maximum control amount has grown at 1.8 percent per year between 2004 and 2016, as shown in Figure 6.

*Figure 6 - GRE’s growth of demand response. Maximum control amount represents GRE’s capability in peak load reduction.*

1.15 **Forecasts**

GRE’s current demand and energy forecasts were developed using the same methodology as our 2014 IRP. The current 2017 forecasts result in very similar growth rates in energy and demand.
Due to the geographic and economic diversity of GRE’s membership, the 20 AR members were broken down into three distinct forecast regions: Metro Region, Northern Region, and Southern & Western Region. By segregating the AR members into three distinct regions, differences in regional weather, air conditioning saturations, space and water heating fuel types, and localized econometric variables were accounted for by region in the forecast process. Residential consumers are a key driver for both energy and seasonal peak demand forecasts.

GRE’s forecasts of demand and energy over the 15-year planning period reflect growth that is below historical growth, but comparable to recent growth. We expect a compounded annual growth rate (CAGR) of 1.3 percent in energy growth over the planning period and a 1.0 percent CAGR in demand over the planning period.

The primary drivers of the demand and energy growth in the forecasts are the increasing numbers of residential consumers in the Metro and Southern & Western areas and a shift from seasonal homes to year-round homes in the Northern region.

Figures 7 and 8 below show our expected energy and demand growth rates over the 15-year planning period. More information about the forecasts can be found in Section 8 and in Appendix D.
Figure 7 - GRE Energy Forecast with High and Low Growth

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Figure 8 - GRE Demand Forecast with High and Low Growth

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1.16 Plan Development

The overarching goal of our planning process is to identify a resource plan that will meet members’ future energy and capacity needs, while retaining flexibility to navigate an evolving industry. As we move through this process, we take stock of where we have been, assess where we are today and project where we are headed in the future.

The planning process—and the future vision of the portfolio we present here—is shaped by our strategies, regulatory and legislative requirements, environmental policy, Commission feedback from previous IRP filings, and stakeholder input. The process begins with data and information gathering, then proceeds to forecasting and capacity expansion modeling, the results of which inform the selection of a Preferred Plan.

GRE developed this resource plan using the following planning process:

- Engage interested stakeholders.
- Determine modeling assumptions and requirements.
- Evaluate conservation and energy efficiency potential.
- Develop econometric energy and load forecasts to determine growth for our AR members.
- Develop system energy and demand requirements using the AR forecasts and adding in Fixed member requirements, transformation and transmission losses, DC line losses, and known future additions or subtractions.
- Develop our load and capability position.
- Identify regulatory and legislative requirements, including externalities and regulatory costs.
Model scenarios that include sensitivities to identify potential expansion plans using a capacity expansion plan optimization model.

- Develop an Expected Values Case and a Reference Case.
- Evaluate reliability, costs, environmental impacts, and risks of different expansion plans.
- Identify a Preferred Plan that meets our members’ needs while complying with all regulatory and legislative requirements.
- Evaluate the impact of key sensitivities on the Preferred Plan to ensure robustness of result across numerous assumptions and sensitivities.

1.17 Legislative and Regulatory Compliance

In developing this resource plan, GRE reviewed all regulatory and legislative requirements for resource plans. We also reviewed and incorporated responses to Commission Orders in our past resource plans. We believe we have responded to all requirements and Orders.

We are in compliance with all currently applicable legislative and regulatory requirements. Our goal is to continue to remain in compliance throughout the planning period.

These requirements include meeting Minnesota’s Renewable Energy Standard, calculating the Renewable Energy Standard rate impact, evaluating our greenhouses gas emissions reductions against state economy-wide goals, considering environmental externalities in our modeling, identifying supply-side energy savings, identifying customer compositions of our member cooperatives, using a capacity expansion model, evaluating Coal Creek Station retirement, addressing hydro energy costs, modeling scenarios where no
market sales are allowed, and achieving 1.5 percent total demand and supply-side efficiency savings.

In 2015 we achieved a 21 percent reduction in our contribution to statewide CO₂ emissions from our 2005 level emissions. This reduction was determined in accordance with methodologies recommended by the DOC. Our total CO₂ emissions from our generation fleet have gone down 27 percent over the same period. Our expansion plan modeling does not reflect meeting MNGEA’s goal of a 30 percent reduction in greenhouse gas emission reductions by 2025. However, we believe this is due to the limitations of the model in that market purchases and sales are restricted in the model. Market purchases and sales are an important component of the MNGEA calculation.

We expect emissions will continue to reduce through continued conservation and energy efficiency, the retirement of Stanton Station, the addition of 400 MW of wind in the early 2020s, flexible operations at Coal Creek Station, and co-firing Spiritwood Station with natural gas.
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2 The Preferred Plan

Our Preferred Plan is detailed in Table 4 below. It reflects our Five Year Action Plan and adds 600 MW of wind beginning in 2029.

Table 4 - GRE’s Preferred Plan

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<td>2032</td>
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<td>Wind Power Purchase Agreement</td>
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The Preferred Plan includes the retirement of Stanton Station in 2017 and the continued operation of all our remaining owned generating resources over the 15-year planning period. Our Preferred Plan also includes continuing our energy efficiency achievements at 1.5 percent.

An IRP is a forward looking long-term planning document, intended to focus on meeting forecasted peak and energy demand over the planning period. A
variety of resources, both supply-side and demand-side, are considered in the analysis. The peak demand and energy requirements plus a required planning reserve margin are targeted to be met through existing and new resources.

This IRP identifies GRE’s plan to meet forecasted peak and energy demand, as well as a cost-effective path toward a low-cost, lower carbon future. Our IRP takes into account the applicable statutes, rules and considerations outlined by the Commission in GRE’s previous IRP filings. Our resource plan is a reflection of GRE’s commitment to provide competitive rates and reliable service to our members in an environmentally sustainable manner.

GRE’s Preferred Plan continues to provide reliable, affordable service to our members in an environmentally sustainable manner in line with our triple-bottom line. Additionally, our Preferred Plan offers optionality to respond appropriately to changes in the market. Our diverse portfolio of owned generation, purchased hydro and renewable energy, partnered with our continued use of energy efficiency and demand response, provides a balanced, cost-effective generation portfolio that best meets our members’ needs.

GRE’s Preferred Plan continues to strategically position our portfolio and continues preparing for a lower carbon future. This plan is already underway through the retirement of a coal asset, implementation of flexible operations at Coal Creek Station, co-firing of natural gas at Spiritwood Station, the addition of new wind resources, and the continued use of energy efficiency programs and demand response and energy conservation.
2.1 Minnesota Administrative Rule for Integrated Resource Plans

Minnesota Administrative Rules 7843.0500 outline several factors for the Commission to consider in evaluating proposed resource plans:

Factors to consider. In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:

A. Maintain or improve the adequacy and reliability of utility service;
   1. Under the Preferred Plan, GRE’s system growth is addressed by the addition of renewable resources and the continuation of our current, reliable generation portfolio.
   2. The Preferred Plan provides adequate capacity and energy to meet our members’ requirements over the planning period.
   3. The Preferred Plan provides adequate capacity to comply with MISO’s Resource Adequacy requirements, including MISO’s Planning Reserve Margin, over the planning period.
   4. The Preferred Plan does not rely on MISO capacity to meet our members’ needs.
   5. As a member of MISO, we have ongoing access to market energy in addition to our resource portfolio.
   6. We are actively engaged with MISO, other utilities and stakeholders in planning and implementing regional and load serving transmission upgrades and additions needed for reliable and economic operation of the electric system.
B. Keep the customers’ bills and the utility’s rates as low as practicable, given regulatory and other constraints;

1. Our resource decisions are subject to the approval of our board of directors. In certain situations, resource decisions also require the approval of our members, as required under the power purchase contracts between GRE and its members. These approval processes ensure that resource decisions are in the best interest of the membership.

2. We are committed to assisting our members in implementing conservation and energy efficiency to help their end-users make the most of the energy they use and to minimize the need for new supply-side resources. GRE and our members have met and will strive to continue to meet Minnesota’s 1.5 percent Energy Savings Policy Goal.

3. We use a capacity expansion optimization model that identifies a least cost plan in developing our Preferred Plan.

4. The Preferred Plan results in lower revenue requirements than many other expansion plans considered.

5. We have improved the utilization of our generation assets through efficiency improvements and commercialization of waste heat and other byproducts of generating electricity.

6. We actively participate in MISO’s energy markets and we pursue bilateral capacity transactions to minimize overall costs.

7. Our Preferred Plan continues the utilization of our low cost and energy efficiency generating facilities through the planning period.
C. Minimize adverse socioeconomic effects and adverse effects upon the environment;

1. We are committed to assisting our members in implementing conservation and energy efficiency to help them and their customers make the most of the energy they use and to minimize the need for new supply-side resources.

2. We plan to meet load growth with conservation and energy efficiency, renewable energy, natural gas and the market.

3. We are supporting our members in their development of distributed energy resources.

4. We are meeting Minnesota’s Renewable Energy Standard.

5. We have reduced our generation fleet carbon emissions by 27 percent in 2015 from 2005 levels.

6. We expect to continue to reduce carbon emissions through flexible operations at Coal Creek Station and co-firing with natural gas at Spiritwood Station.

7. We have improved the utilization of our existing assets and reduced direct and indirect emissions through efficiency improvements associated with combined heat and power (CHP).

8. We are implementing an electric vehicle program to encourage the use of off-peak energy and reduce transportation greenhouse gas emissions.

D. Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

1. We have a diverse and reliable resource portfolio that includes conservation and demand response, renewable energy, hydro, natural gas, coal and biofuels of various sizes, locations, technology types and contract terms.

2. We have considered a range of sensitivities to identify a Preferred Plan that is robust in the face of a changing energy industry.

3. We have negotiated the termination of our obligation to purchase 50 percent of the output of the 379 MW Genoa 3 coal facility in Wisconsin.

4. We are retiring Stanton Station, a 189 MW coal facility in North Dakota. The retirement represents a reduction of coal fired baseload generation in our portfolio.

5. Coal Creek Station has on-site fuel and is not subject to potential rail delivery challenges.

6. We have ongoing access to MISO market energy in addition to the owned and contracted for resources in our Preferred Plan.

7. We are operating Spiritwood Station, an efficient CHP facility, and are now co-firing the station with natural gas.

8. We actively monitor the actions of the regulatory authorities, including the Commission, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Midwest Reliability Organization and others. We also participate in organizations and stakeholder groups that have an energy focus, including
Electric Power Research Institute (EPRI), National Rural Electric Cooperative Association (NRECA), Minnesota Rural Electric Association (MREA) and others to monitor and anticipate developments that may impact us.

9. We are fully engaging with our members in Grid Modernization initiatives, including pilot programs and data analysis.

2.2 Future Resource Needs

GRE holds a capacity surplus in excess of our load requirements and MISO’s planning reserve margin requirement (PRMR) for the planning period of 2018-2032. MISO’s tariff requires us to maintain adequate resources to serve our system load and to add the PRMR for compliance with its Resource Adequacy tariff. The MISO PRMR is currently 7.8 percent.

We calculate and plan our peak load coincident with MISO’s summer peak, which represents a 10 percent diversity factor with our system peak. This effectively lowers our planning requirements. We must have adequate resources to meet 90 percent of our MISO coincident peak load requirements plus 7.8 percent PRMR. More information on this process is included in the plan development description in Section 9.

Figure 9 below reflects our Load and Capability position over the planning period with our Preferred Plan. The bars reflect our accredited capacity, and the line reflects our MISO coincident peak load requirements with the added required PRMR. The figure includes our new wind additions in 2020 and 2021 and from 2029-2032. The figure also includes the retirement of Stanton Station.
GRE has adequate resources to meet our requirements through the planning period.

*Figure 9 - GRE Capacity Position over the Planning Period*

We seek to optimize our capacity position by selling capacity to other load serving entities in our region. The bilateral transactions are beneficial for both GRE and the purchasers, in that the capacity is priced at lower cost than building new generation resources and the purchase assists the purchasers in meeting their capacity needs. The sales provide benefit to GRE by bringing in additional revenues that lowers costs to our members.

### 2.3 Integrated Resource Planning

GRE’s integrated resource planning process is a continuous cycle of evaluation and assessment of industry changes and our portfolio’s ability to meet our members’ needs in a low cost way. Our planning process begins with the
We work with our board of directors on scenario planning, and maintain awareness of the changing energy industry. We communicate with internal and external stakeholders. We update assumptions for existing and new generation, renewable energy profiles and costs, externality costs, and market and natural gas prices.

We perform econometric energy and demand forecasting to determine expected high and low growth scenarios, which are then input into our capacity expansion model. We use the model to economically optimize the portfolio and ensure that we meet our load and energy requirements. We run sensitivities on key variables to identify the most robust capacity plan across a broad range of assumptions that has a low net present value of revenue requirements over the planning period while meeting our board of directors and member requirements.

An Expected Values Case is developed, using expected assumptions for all inputs and variables. These assumptions include expected load, penetration of conservation and energy efficiency, distributed energy resources, electric vehicles penetration and compliance with Minnesota’s Renewable Energy Standard. The Expected Values Case serves as the baseline against which we evaluate the impacts of sensitivities like market and natural gas prices, and energy and demand growth. We then create a Reference Case which includes the required regulatory costs and externality values. Finally, we run cases that were requested by external stakeholders.

We assess costs and other impacts of the resultant expansion plans and identify the Preferred Plan that is the most robust across expected sensitivities while meeting all requirements.
A more thorough summary of GRE’s forecasting and modeling processes are described in Section 9 and in Appendix D, respectively.

### 2.4 Stakeholder Discussions

Over the past several years, GRE has engaged in important external stakeholder outreach and engagement related to resource planning. This past year, several discussions were held with stakeholders to the IRP, including a November 2016 meeting with the Coalition of Environmental Organizations (CEOs) and the Center for Energy and Environment (CEE). This meeting incorporated a wide-ranging discussion of current issues facing GRE, and steps that we are taking to position our generation portfolio for a potential lower carbon future. GRE also communicated with the CEOs during our modeling process to inform the group about our assumptions and modeling.

In addition, GRE met with the Department of Commerce, division of Energy Resources (DOC) in December 2016 at the offices of the DOC in Saint Paul, Minn., to discuss GRE’s conservation programs, and to give an update regarding the generation portfolio and the transition of GRE’s system to adapt to a lower carbon future. Additionally, GRE presented its forecast and modeling results to the DOC on March 21, 2017.

Dates and participants to meetings as part of GRE’s stakeholder outreach process are listed below.

- **External stakeholder meeting - March 31, 2016, in Maple Grove, Minn.**
- **CEOs (MCEA, Sierra Club, Wind on the Wires) and the Center for Energy and Environment (CEE) – Nov. 9, 2016 in Maple Grove, Minn.**
2.5 Preferred Plan

Our Preferred Plan includes our Five Year Action Plan and adds 600 MW of wind beginning in 2029.

Our Preferred Plan provides optionality and reliability of energy supply for the future, one in which historical baseload power generating resources must adapt to increased penetration of large amounts of wind and other variable resources. We continue efforts to transition our portfolio, our grid modernization initiatives, and to plan around a carbon-constrained generation environment. We are encouraging electrification of the economy, and we plan to provide our members with reasonably priced power that is reliable and considers environmental policy and regulatory changes.

Our Preferred Plan satisfies GRE’s internal directives and the requirements set forth in statute, state rules, and previous Commission orders. A full overview of compliances with all applicable requirements is located in Appendix A.

GRE will operate Coal Creek Station more flexibly, incorporating our response to recent market changes in the way we ramp the plant. Spiritwood Station has two primary purposes, to supply electricity and to supply process steam to two
(with a recently announced third) commercial customers near the station. Spiritwood Station now has the capability to co-fire with natural gas, which we implement when economical to do so. The operational flexibility at Coal Creek Station and fuel flexibility at Spiritwood Station have allowed us to adapt to lower market prices and lower gas prices.

The Preferred Plan includes the capacity additions shown in Table 5:

*Table 5 – GRE’s Preferred Plan*

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2.6 Five Year Action Plan

Our Five Year Action Plan is to:

- Retire Stanton Station.
- Continue to operate all other owned generation units.
- Increase the flexibility of Coal Creek Station operations.
- Continue implementing cost-effective opportunities at our facilities to lower emissions and provide greater customer value through efficiency improvements.
- Continue to co-fire natural gas at Spiritwood Station when economic.
- Add 300 MW of wind beginning in 2020.
- Add 100 MW of wind beginning in 2021.
- Continue our demand-side management (DSM), and demand response (DR) initiatives.
- Continue engagement with our members on grid modernization initiatives.
- Encourage environmentally beneficial electrification initiatives.
- Comply with all environmental and regulatory requirements.
- Continue our energy policy discussions with our members as well as state, regional, MISO, regulatory, and national energy groups to help shape our future.
- Continue to work with our members in implementing distributed energy resources.
- Ultimately, to serve our members with low cost, reliable and environmentally responsible power.
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# 3 Innovative Initiatives

With our members, GRE is engaged in several innovative initiatives to address current and future needs including:

- Working with our members to develop distributed energy resources.
- Continuing and enhancing our efficiency and demand response programs (See Sections 6 and 7).
- Continuing work on reducing carbon emissions in our portfolio.
- Participating in the development of grid modernization.
- Pursuing environmentally beneficial electrification of the economy.
- Promoting electric thermal energy storage and heat pump water heating.
- Facilitating economic development in our members’ service territories.

## 3.1 Distributed Energy Resources

GRE and our members are developing distributed energy resources. In addition to GRE-developed renewable resources, our AR member are entitled to undertake renewable energy development projects on their own, up to a maximum of five percent of their energy requirements. We refer to such member-owned facilities and power purchase agreements as Member Renewable Resources.

We support our members in developing these local Member Renewable Resources. Our AR members have 11 community solar projects installed throughout their service areas and more under development. These are in addition to the 650 kW of solar projects that GRE has installed at our headquarters office in Maple Grove and at the offices of 19 of our AR members.
Our members, with our support, are increasing development of distributed energy resources in their service territories. Our AR members have added nearly two megawatts of renewable energy in their service territories as part of the five percent member option, with several more megawatts of distributed solar resources currently in development or under consideration. Our Fixed members do not have the opportunity to take part in the member option; however, Fixed members have added more than two megawatts of renewable resources.

We continue working with interested members to further their utilization of the Member Renewable Resource option.

3.2 Reducing Carbon Emissions in our Portfolio

GRE has taken significant steps to transition our portfolio to lower greenhouse gas emissions from our portfolio. We have reduced our total carbon emissions across our generation fleet by 27 percent since 2005. We continue to further reduce emissions by expanding our renewable energy resources. Our 2016 capacity by fuel type was 40 percent coal, 35 percent natural gas, and 22 percent carbon free generation and three percent fuel oil. This compares with 52 percent coal, 31 percent natural gas and 14 percent carbon-free generation in 2005.

We have added 468 MW of wind since 2005. We negotiated the termination of our obligation to purchase 50 percent of the output of the 379 MW coal fired Genoa 3 facility in 2014. In July 2016 we announced we would retire Stanton Station by May 2017. Figure 10 below shows that, for the first time in our
history, our natural gas generating capacity will exceed our coal generating capacity following the retirement of Stanton Station in 2017.

We have identified and are implementing ways to operate Coal Creek Station more flexibly in order to better respond to the growing amount of wind generation in our region that is causing baseload facilities to become wind following facilities. We are using natural gas at Spiritwood Station when natural gas prices are economical, and are looking at expanding our gas co-firing capacity. We continue to evaluate options to improve the overall operating efficiencies at the plants.

GRE plans to almost double our wind capacity by 2021. We currently have 468 MW of wind in our portfolio. We have procured an additional 300 MW of wind beginning in 2020, and we have finalized an agreement for an additional 100 MW of wind beginning in 2021.
GRE’s first addition of solar was at our headquarters where we installed 72 kW of solar photovoltaic capacity in 2006. We then expanded to 322 kW in 2014. GRE and our AR members have installed over two megawatts of solar generation in member service territories and we are planning for several more megawatts of additional solar development. Our Fixed members also currently have more than two megawatts of solar generation.

### 3.3 Grid Modernization

GRE and our member cooperatives are actively preparing for the grid of the future. We have formed an internal steering committee, drawing from GRE and member staff, spanning a wide variety of backgrounds and expertise. Some of the key objectives of the formation of this committee are to develop a shared vision of the future and to explore potential for shared technology platforms.

We understand that new technology has brought significant changes to how consumers think about and use energy, which will impact how we can potentially serve their needs in the future. We have a very diverse membership, and our members are at various stages of deploying new smart technologies that are needed to take advantage of the more connected grid of the future. A technology roadmap has been created to illustrate the partnership necessary to make deployment of these technologies timely, and cost-effective.

The roadmap has five pillars:

- **Telecommunications infrastructure**, which includes three critical components – the fiber backhaul system, the 700 MHz wireless
broadband (SCADA) network and the trunked mobile radio system. In partnership with member cooperatives, we plan to build a foundation for smarter energy and deliver solutions and services.

- **Advanced metering infrastructure (AMI)**, which fulfills an integral role in providing data to members and cooperatives. AMI automates metering functions using communication networks and eliminates the need for field collection and on-demand polling of meters to verify an outage or restoration. Data collected through AMI can be used to identify customer consumption patterns and identify maintenance needs.

- **Meter data management system (MDMS)**, which helps monitor line losses, transformer losses and power theft, and helps to accurately bill accounts with intermittent generation such as solar.

- **Demand response management system (DRMS)**, which allows us and our members to better adapt to changes in technology, consumer expectations and market forces. A DRMS is the analytics engine for demand response. It will help cooperatives better understand the impact of demand response, control electric loads at a more granular level and interconnect with other load control technologies.

- **Energy management system (EMS) and distribution management system (DMS)**, which are systems of computer-aided tools to monitor, control and optimize the performance of the generation and/or transmission system. A DMS is a collection of applications designed to operate the distribution network efficiently and reliably. We, along with our member cooperatives, use both systems to collect data and remotely operate the transmission and distribution systems.

GRE continues to analyze the work necessary and the investments needed to make the transition to serve our membership in a quickly evolving world and into the future. Cooperatives like GRE are in an excellent position to operate as
innovators in the grid modernization arena. We bring new options and ideas to our membership and we continue to work with our members to develop new and exciting projects, driving the implementation of our grid modernization initiatives forward.

GRE is pursuing several grid modernization pilots with our members. We have been active in the Commission’s grid modernization stakeholder process, where we have taken part in panels, discussions and meetings to discuss the future of grid evolution in Minnesota. A summary of GRE’s grid modernization efforts, pilots, and projects accompanies this filing in Appendix G.

3.4 Environmentally Beneficial Electrification of the Economy

Environmentally beneficial electrification of the economy presents opportunities to reduce greenhouse gas emissions across the economy and to beneficially impact the load shape of our system. This concept is a focus of ours moving forward. We believe it is imperative to achieve further decarbonization of the U.S. economy.

Research is increasingly suggesting that end-use electrification is one of the most important actions toward achieving significant greenhouse gas reductions. The deep decarbonization goals such as those discussed at the Conference of Parties 21 (COP21) commonly referred to as the Paris Agreement, and Minn. Stat. 216H.02 Subd. 1, which sets a goal of an 80 percent reduction relative to 2005 levels for statewide greenhouse gas emissions by 2050, are not going to be possible by simply addressing the power generation sector.
The Brattle Group (Brattle) released a report in January 2017 titled “Electrification, Emerging Opportunities for Utility Growth,” which has been included with this IRP as Appendix I. The report used Energy Information Administration (EIA) data as the base forecast of economy-wide annual greenhouse gas emissions in conjunction with the National Renewable Energy Laboratory’s (NREL) estimates of rooftop solar PV technical potential to evaluate the impact of distributed energy resources on decarbonization goals. The report found that even with 100 percent of the NREL rooftop solar technical potential realized economy-wide, there was a marked inability to achieve the aggressive decarbonization goals as shown in Figure 11.

Figure 11 – Carbon Reductions with Maximum Solar DG Potential

Brattle goes further in its analysis and postulates a fully decarbonized electric sector in 2050. In that case, the results still showed only a 36 percent reduction in the U.S. energy-related greenhouse gas emissions, leaving a 2,400 million metric ton gap as shown in Figure 12 below:
Both of these results indicate that the solution to a deep decarbonization economy-wide cannot be driven solely by the supply-side decarbonization of the electric generating sector nor the uptake of distributed renewable energy resources, but rather that significant reductions in greenhouse gas emissions must come from sectors other than the electric generation sector. The report highlights water and space heater electrification, in addition to electrification of the transportation sector as key to long-term deep decarbonization, and indicates that full electrification of heating and transport could affect a 72 percent decrease in CO₂ emissions levels from 2015 base as depicted in Figure 13.
The potential benefits of electric end-use technology presents the possibility to change those end-use technologies’ carbon intensity as the resource mix of the electricity supply changes. As supply-side resources become more renewable, and less carbon intensive, the electric end-use technologies become more emissions-efficient in turn, and will have lower associated greenhouse gas emissions.

Environmentally beneficial electrification presents an exciting path forward for both the utility business model and the potential for future decarbonization. Our resource plan filing has considered the impact of electrification of the economy to some extent in our high forecast sensitivity and our electric vehicle penetration sensitivity, both of which are illustrated in Section 9.

Our programs and efforts on environmentally beneficial electrification include our work with electric vehicles, a pilot battery electric school bus program, our
electric thermal storage network, and heat pump water heating, as discussed below.

### 3.4.1 Revolt Electric Vehicle Program

Electrification of the transportation and heating sector can help to achieve deep greenhouse gas reductions. GRE’s research has indicated that members choose to own an electric vehicle (EV) primarily for environmental reasons, so we sought to design a program that would make that decision more attractive. GRE has a commitment to develop the EV market, with the assistance of our members.

As a means to promote EVs, GRE’s Revolt program offers 100 percent renewable energy for EV charging at no additional cost for the life of a vehicle or term of a lease. With Revolt, GRE seeks to incent the adoption of electric vehicles by retiring Renewable Energy Credits (REC) for EV charging.

Annually, an EV driver uses 4,000-5,000 kWh for the 10-year average life of a purchased EV. Through the Revolt program, GRE retires 50,000 kWh of RECs for purchased EVs and 15,000 kWh of RECs for leased vehicles to guarantee the efficacy of its 100 percent wind energy program.

### 3.4.2 Battery Electric School Bus Pilot

There is broad public and governmental support for reducing greenhouse gas emissions from the transportation sector. Building from the work that GRE has done with EVs in our Revolt program, we are also pursuing the purchase of a battery electric school bus (BESB) with the intent of piloting a BESB program in
Minnesota. We are willing to champion a BESB pilot program because it can benefit our members, their communities, and the environment.

The BESB pilot program would serve to showcase new energy efficient technology, offer opportunities to shape load, demonstrate performance of BESBs in cold climate areas, and could help to document the economics and the environmental emission reductions from switching to BESBs from traditional diesel buses. BESBs can further enable the integration of renewable generation on distribution systems since buses typically operate in the morning and in the afternoon. The buses can then recharge at mid-day or at night, which generally coincides with the production of solar PV technology and wind generation. This capability can make the BESBs a source to store off-peak renewable generation for use during peak demand time when renewable generation is no longer producing to serve load. The potential for BESBs to have beneficial impacts is fourfold:

1. A reduction to the air emissions of standard, diesel school buses;
2. Opportunity to shape load;
3. A reduction in overall greenhouse gas emissions; and
4. Facilitating integration of renewable generation production with peak demand hours.

New, dedicated BESBs currently cost significantly more than a conventional diesel school bus (approximately $400,000 for a BESB compared to $100,000 to $125,000 for diesel). We will actively pursue grant funding through federal and state programs, but recognize that a shared cost approach with capital contribution commitments from each of the major participants may be necessary. Grant funding would reduce the participants’ share of the program cost.
3.5 Electric Thermal Storage

Since 1980, GRE and our members have offered larger capacity storage water heating as an overall cost-saving strategy for the members’ end users. The program requires the use of large capacity water heaters, typically 80 gallons and larger, which are programmed to consume electric energy between 11 p.m. and 7 a.m. each night. This strategy satisfies the hot water needs of the members’ end-use participants with off-peak electricity. The savings associated with these purchases are passed along to our membership. More than 65,000 end-use members are taking advantage of the electric thermal storage (ETS) strategy to meet their water heating needs.

During the eight-hour charge period, each water heater has the potential to utilize the electric equivalent of 122,832 Btu (36 kWh), assuming a 4.5 kW heating element. This is sufficient energy to raise the temperature of approximately 134 gallons of water 110 degrees Fahrenheit. On average, participants in the ETS water heater program consume approximately 4,800 kWh annually (13 kWh per day), or 36.5 percent of the total potential charge to meet the water heaters set point. This level of consumption correlates well with data reported by the EIA 2009 Residential Energy Consumption Survey, which reported water heating consumption to be approximately 17 percent of total energy consumption in the West North Central Census Division, or 17,000,000 Btu, and 15 percent of total energy consumption in the state of Wisconsin, or 15,450,000 Btu.

The EIA 2009 Residential Energy Consumption Survey did not break out Minnesota’s state specific energy consumption by end uses. The total consumption of 4,800 kWh is equivalent to 16,377,600 Btu. The ability to effectively store kilowatt-hours in large capacity water heaters without a
negative end user experience effectively makes the ETS water heater program a very large system battery. On average we and our members store more than 845,000 kWh via ETS water heaters each night. These kilowatt-hours are increasingly generated by renewable resources.

We have tested various communications technologies that could enable ETS water heaters to serve a greater role in grid management by providing ancillary services. Such an approach would result in faster response times to ancillary services signals that are sent out by the grid operators and could reduce the carbon intensity of providing these services to the market. In addition to the regular control signal that turns a water heater on or off based on the time of day, grid-interactive water heaters also have a market signal that would indicate when to turn a water heater on or off in an effort to provide a means of balancing the system.

We have been working closely with providers of the control systems as well as determining the necessary ancillary services requirements that would need to be in place to enable this strategy. We are currently piloting the effort with a small number of units with one of our members.

We have worked closely with the National Rural Electric Cooperative Association, the Peak Load Management Alliance, the American Public Power Association, Steffes Corporation, and the National Resources Defense Council to identify an option to continue offering ETS water heating programs to end use members. We continue to work on regulatory and legislative solutions that will enable the continued operation of its ETS water heater programs.
3.6 Heat Pump Water Heating

Heat pump water heaters (HPWH) represent the next generation of water heater efficiency. While current HPWH models have the ability to realize an energy factor (EF) greater than 2.0, compared to 0.92 for large capacity ETS water heaters, there are sufficient concerns regarding their performance in northern climates to warrant cautious optimism. HPWH technologies utilize the same vapor compression cycle found in refrigerators, dehumidifiers and central air conditioning. In the case of a HPWH, the vapor compression cycle is utilized to “move” heat from the air around the HPWH into the hot water storage tank. This is very effective in warmer climates, where the water heater can often be found in the garage or some other unconditioned space. Most of the water heaters in Minnesota will be located in a semi-conditioned basement or within a conditioned space. During the winter months this results in the HPWH cannibalizing warm conditioned air to heat the water in the hot water storage tank.

While the level of efficiency may be sufficient enough to overcome this technology shortcoming, there are additional challenges relative to our controlled water heater programs. HPWH technologies tend to operate at lower energy consumption for longer periods of time, which may limit the application of the ETS water heater strategy to HPWH products. While the efficiency of the product will provide end use benefits, their inability to utilize off-peak energy for water heating is less than desirable.

Another complicating factor of HPWH is the ability for users to set a variety of operational modes, which make characterizing the end use load curves of these technologies difficult. Current operational states include: Eco- or Heat Pump Only-mode; a hybrid mode, whereby the heat pump is assisted with electric
resistance elements to obtain a quicker temperature rise; and electric-only mode, whereby only the electric elements are used to provide water heating. There are likely to be greater operational modes and features as additional products enter the market. While a strict adherence to the most efficient modes of operation can reduce the total electric consumption by 50 percent, there are ongoing questions regarding consumer acceptance of these technologies.

Our water heating control programs are focused on reducing the monthly peak demand each month of the year. This reduces the wholesale electric costs to our members and ensures that we effectively capture value from our load management system throughout the year. We have limited experience with applying load control to HPWH technologies. A short pilot conducted with cooperative employees between 2010 and 2011 suggested that such control strategies could be applied, but that member satisfaction with the controlled hot water program could suffer. We continue to work with researchers such as EPRI and the Cooperative Research Network to identify the best means of integrating HPWH technologies into our system.

Assuming there are no changes to the federal water heating standards, we are prepared to continue to evaluate options for our ETS programs. Certainly, we will see a continuation of program operation for some time, as the new standards apply only to the manufacture of new water heaters. Over time there will be a reduction in the program due to attrition, which will force our members to adopt HPWH technologies or electric water heaters having a capacity of 55 gallon or less. While there will be attempts to enroll as many of these units in existing interruptible water heating programs, it is expected that under either scenario, there is likely to be an increase in peak impacts associated with water heating.
3.7 Economic Development

GRE’s economic development efforts support our members’ growth by providing services designed to attract and expand commercial and industrial businesses within our members’ service areas. These efforts fall into four main categories: business recruitment, business retention and expansion, community preparedness, and communication and outreach. In times of continued low load growth for utilities, it is imperative that we continue to maximize our impact in our members’ by supporting jobs, encouraging economic growth and encouraging beneficial load growth.

Target industries are determined by analyzing the service area of each of our member cooperatives to identify business sector growth opportunities. We evaluate the energy demand and usage statistics of the businesses identified to focus on a specific industry, which is then pursued through multiple avenues and in conjunction with economic development partners. As the electric utility partner, we assist our communities in providing thorough and detailed responses to business attraction opportunities. We take a lead role for our members in marketing and positioning our service areas to national and international industry trade groups and real estate professionals to maximize visibility and attract new opportunities.

Working with our members, we engage in business retention and expansion by providing direct financing to assist with energy efficiency improvements, as well as access to capital for construction projects through the Rural Economic Development Loan and Grant Program offered by the Rural Utility Service of the United States Department of Agriculture (USDA). We also provide loan packaging and technical assistance on many cooperative economic development financing programs across our membership.
GRE works with our members to identify optimal locations for economic growth to ensure the economic competitiveness of the communities in our member cooperative service areas. Communities throughout our members’ service territories benefit from infrastructure development and improvements in partnership with us and our members. We maintain up-to-date inventories of available land and buildings and our economic development team actively responds to project inquiries.

GRE continuously refines our economic development communications to educate, inform and promote our business opportunities. We focus on developing new communication channels while enhancing the content and utilization of our existing methods. We maintain an economic development newsletter which includes relevant industry articles, economic development activity and related events across our service area.

The economic development services team maintains strong relationships with national, state and regional trade and development organizations to keep abreast of industry trends and opportunities. We strive to develop programming that is relevant to our target industries and enhances the efforts of our economic development partners. An example of this is our Data Center Site Assessment Program.

GRE’s Data Center Site Assessment Program is designed to determine the suitability of a particular site for a data center development. We enlisted Deloitte Consulting’s Real Estate & Location Strategy practice to establish the evaluation criteria and program parameters. The evaluation criteria represent site location factors known to be highly important to data center developers. In order to receive a designation, sites have to pass a multi-level review of the
available infrastructure, surrounding uses, local government and demographic information. The sites receiving a “primary” designation meet or exceed all of the assessment criteria and are ready to market for immediate data center development.

GRE promotes sites at data center industry events throughout the country and to interested companies, significantly increasing the chances of securing new data center development. Minnesota is considered a premium location for data center development due in part to one of the most aggressive state incentive programs for data centers. Our site assessment program offers increased speed-to-market, which is one of the top drivers for this type of project. Since the program was established in 2014, we have seen an exponential increase in the number of data center project requests for information and size of projects inquiring in our members’ service locations. Project size on new inquiries is trending upward, from the 10 MW and under demand requirements currently seen in Minnesota data centers, to 50 MW and above, and even up to 200 MW for certain large facilities. These large load potential projects represent a very real and large growth opportunity for our business, and for the economic development of our members.

In 2015, we celebrated the grand opening of a DataBank data center in Eagan, Minn. This multi-award-winning co-location data storage facility and carrier hotel was the culmination of a lengthy business attraction effort by Dakota Electric Association, GRE and partners. This collaborative effort was recognized by the Economic Development Association of Minnesota as the 2015 Business Recruitment Project of the Year. DataBank also received a 2015 Progress Minnesota Award from Finance and Commerce.
Faribault Foods broke ground in 2016 on an expansion that will more than double the size of their facility in Faribault. The nearly 600,000-square-foot building expansion will be used to manufacture food, and will help to further develop Minnesota’s world-leading agriculture and food sectors. We worked alongside our member cooperative Steele-Waseca Electric Cooperative to ensure Faribault Foods’ energy needs were met in a cost-effective manner. We also coordinated efforts with the Department of Employment and Economic Development, the city of Faribault and other partners involved to help make this project a reality.

Aubright, a well-established St. Cloud, Minn. plastic fabrication company that serves customers in the retail, original equipment manufacturers (OEM), and power sports markets nationwide, received financing from us in 2016 to acquire a specialized plastics thermoforming machine. The new equipment allows Aubright to expand product offerings, meet increased demand from clients and streamline its production process. Aubright employs approximately 100 people at its 80,000-square-foot facility in the I-94 Business Park, and is a large-load industrial customer of our member cooperative Stearns Electric Association.

Serenity Living Solutions, a 16-unit assisted living facility in Remer, Minn., opened its doors to residents in 2016. The facility received a USDA Rural Development Loan acquired through its electric cooperative Lake Country Power and the economic development services team of GRE. The project created ten new full-time jobs with competitive salaries in a rural community of 362 that has experienced steady population decline and job loss.
We will continue to work closely with our members in the areas of economic development to help our members, their end users, and their communities remain healthy and strong.
4 Environmental Update

GRE’s goal is full compliance with all applicable environmental regulations. We are preparing to comply with all expected future environmental regulations. Consistent with our triple bottom line, we have worked hard to reduce the environmental impact of our business operations. Between 2005 and 2015, we achieved the following emission reductions across our generation fleet:

- Carbon dioxide (CO₂) emissions have decreased by 27 percent;
- Total sulfur dioxide (SO₂) emissions have decreased by 61 percent;
- Total nitrogen oxides (NOx) emissions have decreased by 49 percent.

Appendix H provides a complete update to significant environmental regulations that currently apply to GRE’s generation resources, as well as those which are pending at this time. However, as a result of the November 2016 election we anticipate there will be changes to environmental policy and requirements. We closely monitor the U.S. Environmental Protection Agency’s (EPA) activities with respect to any regulations that may impact our operations.

We will remain fully engaged with environmental regulatory changes, on both state and federal levels, and are prepared to take actions necessary to comply with new requirements. We also monitor legislative changes and are prepared to respond accordingly such that we remain in compliance with any changing or new standards to which we are held.

Significant environmental regulations that impact GRE operations include the following:
Acid Rain Program;
Regional haze rule;
Cross-State Air Pollution Rule;
Mercury and Air Toxics Standards rule; and
Coal Combustion Residuals rule/management.

For other existing and emerging regulations, we cannot predict what the final requirements will be and what their effect will be on our resources. Nevertheless, we have included a discussion in Appendix H of the status of the following regulations and their potential impact to our facilities:

- Greenhouse gas emissions;
- Regional haze rule – second phase;
- National Ambient Air Quality Standards – these standards are both existing and emerging;
- Aquatic life protection at cooling water intake structures rule (Clean Water Act §316(b)); and
- Phase-out rule for polychlorinated biphenyls in electrical equipment.

In addition to our regulatory compliance efforts, we are continuing to enhance our environmental stewardship by adding renewable resources to our portfolio, operating our facilities in accordance with ISO 14001 registered environmental management systems, investing in emission controls, and developing commercial uses for our facilities’ byproducts.

We will retire Stanton Station on May 1, 2017. As such, the discussion of environmental issues and regulations in Appendix H does not include any impacts to or compliance actions taken relative to Stanton Station.
5 Current Market Outlook

GRE joined the Midcontinent Independent System Operator Inc. (MISO) in 2004, and has participated in the MISO markets since the markets began operating in 2005. The MISO markets have evolved and continue to change. In the MISO energy market, we no longer plan our generation and transmission resources to directly supply our members’ power supply requirements. As a MISO member, all of our members’ energy needs are supplied directly from the market. We sell all of our generation output into the market. As a result, the market is a significant consideration in our resource portfolio decisions.

5.1 MISO Market Conditions

The MISO resource adequacy construct breaks the geographic areas of the large MISO footprint into 10 local resource zones (LRZs). This was done to consider the geographic locations of load and generation resources such that demand and Loss of Load Expectation (LOLE) requirements are met in each geographic area. GRE’s generation is largely located in LRZ 1. We serve a small amount of load in LRZ 3. Market changes in LRZ 1 have impacted our resource decisions. Falling market prices for natural gas and an increasing supply of wind energy have combined to reduce market prices for energy across MISO, especially in LRZ 1.

Gas production in the United States has been increasing at historic levels over the last decade, driven by new technology and methods of extraction. In 2015, the U.S. reached a record production level of 79 billion cubic feet per day (Bcf/d).
Figure 14 shows the EIA is projecting increases to U.S. dry natural gas production in 2017 from 2016 levels, and additionally a forecasted increase in 2018 from 2017 projections. New export capabilities and increased domestic consumption contribute to the increased production estimates from the EIA. Additionally, impacts from policies of the new administration at the federal government level may have impacts to the production of natural gas and import/export policies that would have an effect on production and imports into the future.

Wholesale electricity prices are very sensitive to changes in the price of natural gas. Natural gas will often set the marginal price in energy markets. The EIA data have indicated a surge in production of natural gas in the U.S. over the past several years which, in concert with increased imports and warmer than average recent winters, have forced a resulting decrease in natural gas prices. This natural gas production and trend toward lower prices have resulted in
significant downward pressure on power market pricing in most markets. Specifically in MISO, the Independent Market Monitor (IMM) 2015 state of the market report outlines the downward trend:

The all-in price in 2015 fell 29 percent from 2014 to average $28.91 per MWh. The large decrease was driven by much lower natural gas prices, declines in other fuel prices, and increased wind generation. MISO also experienced relatively mild weather and corresponding load levels through much of 2015. The average price of natural gas decreased more than 50 percent from 2014 to 2015 and the average mine-mouth coal price fell 17 percent from 2014.¹

The suppression of MISO market prices by commodity pricing trends has been further exacerbated by the level of wind development in the MISO Upper-Midwest, namely in LRZ 1. Wind development in MISO North Dakota, South Dakota and Minnesota has grown over the past decade from just over one gigawatt (GW) of nameplate capacity wind generation in 2006 to over 16 GW of nameplate capacity generation in 2016, as illustrated in Figure 15 below. Figure 16 reflects MISO’s own projections that the growing trend in wind is expected to continue, with estimates of almost 22 GW of nameplate capacity wind generation by the end of 2020.

The development of wind resources in MISO has primarily been concentrated in the Upper Midwest. Figure 17 shows MISO’s monthly assessment report data for January of 2017, which indicates that the Northern Region of MISO had a high level of dispatched generation coming from wind resources. The bulk of MISO-wide wind development is coming into the Northern Region versus the Central and South Regions of MISO.
The Production Tax Credit (PTC) encouraged a tremendous amount of wind development in the MISO region. Wind generation tends to be at the bottom of the MISO dispatch stack, meaning that wind resources are offered into the day-ahead market at very low prices. As these resources get picked up in the market at low prices, there is a resulting impact to energy market prices, especially at a regional level, where there may be insufficient transmission capacity to move the wind generated electricity to load. In order to balance the grid, market prices sag to very low levels in order to back down higher priced generation that receives no production tax credits.

Suppressed market prices influenced our decision to retire Stanton Station in 2017, and also influenced our decision to become more flexible and reactive to market price signals at Coal Creek Station. The continued low market prices in the Upper Midwest are expected to persist into the future due to the significant amount of wind generation in the area.
GRE recovers costs through MISO locational marginal price payments at specific generator nodes. Stanton Station and Spiritwood Station generation nodes are located in North Dakota, whereas Coal Creek Station’s generation node is in Minnesota. This is because the high voltage direct current (HVDC) transmission line that carries the station’s output terminates in Minnesota.

The power market price declines over the past decade are illustrative of the quickly changing market conditions under which GRE is operating.

### 5.2 Stanton Station Retirement

GRE’s decision to retire Stanton Station was predicated on the low market prices that have been occurring in MISO and that are expected to continue, as well as the need to make improvements at the 50-year-old plant. We are starting to execute plans to decommission and demolish Stanton Station in a responsible manner that will safeguard the local environment and assure the safety and security of the local community.

The data in Table 6 below were sourced from MISO nodal market data for Stanton Station (GRE.STANT01) and MISO’s Minnesota Hub (MINN.HUB). The Minnesota Hub is a representative pricing node that demonstrates the general trend in Locational Marginal Prices (LMP) in our area, while the Stanton Station node is specific to Stanton Station. The prices are average 7x24 LMPs.

The data demonstrate the changes to LMPs over the last decade, reflecting the decline in market prices as a result of low gas prices and increased wind generation.
Table 6 - MINN.HUB and GRE.STANTO1 LMP Prices 2007-2017

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<td>MINN.HUB</td>
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<tr>
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Over the past decade, the Stanton nodal 7x24 LMP has steadily declined from more than $29/MWh on average to less than $19/MWh. From 2007 to 2017, the MINN.HUB price has decreased by more than $12/MWh. Both nodes have exhibited more than a 30 percent decrease in the 7x24 LMPs, and interestingly a decrease in the standard deviations around the new lower average prices. We believe the reduced average prices and the reduced deviations in the 2015-2017 period are the result of lower natural gas prices and increased wind development in the Upper Midwest.

As part of the retirement process, GRE initiated and completed MISO’s Attachment Y process for Stanton Station in 2016. MISO reviewed the retirement of the unit for power system reliability impacts and found that retirement of Stanton Station would not result in violations of applicable reliability criteria that would otherwise require Stanton Station to remain in operation as a System Support Resource. The Attachment Y process is final and we plan to retire Stanton Station on May 1, 2017.
5.3 Coal Creek Station

Coal Creek Station, located five miles south of Underwood, N.D., is a two-unit, 1,146 MW coal-fired generating facility. The mine mouth plant, adjacent to North American Coal’s Falkirk Mine, burns lignite processed through GRE’s DryFine™ system.

Coal Creek Station is an economic and efficient generation station. It applies a CHP process and DryFine coal, helping to increase efficiency and reduce carbon emissions. We are beginning to more flexibly operate the station to match lower market prices and to provide energy when intermittent resources are not available. This change has allowed Coal Creek Station’s two units to effectively ramp across their full capable range, based on real-time market signals in the MISO region.

In effect, we are changing the mission of the station from producing at a very high capacity factor to providing reliability to the market and serving as a back-up for growing wind energy in the region.

Coal Creek Station continues to make beneficial use of nearly all the fly ash it produces. Much of the fly ash is sold as a substitute for Portland cement in concrete infrastructure projects throughout Minnesota and the Dakotas. The EPA has determined that 0.8 tons of CO₂ emissions are reduced for every ton of Portland cement replaced.

Coal Creek Station is a reliable generation resource for our members. The station provides our greatest hedge against market prices for our load. It is fully in compliance with state and federal environmental standards. We expect
Coal Creek Station to continue operating well into the future. We have no plans to retire Coal Creek Station.

### 5.4 Spiritwood Station Combined Heat and Power Facility

Spiritwood Station, located nine miles east of Jamestown, N.D., is a CHP facility that has the capacity to generate up to 99 MW of electricity and supplies process steam to industrial customers near the plant. Spiritwood Station uses Best Available Control Technologies to control emissions. Spiritwood Station commenced commercial operation in 2014.

Spiritwood Station differs from traditional electric generating plants in that its purpose is to generate both electricity and process steam. Its steam customers include two adjacent agriculture processing plants: an ethanol biorefinery and a malting facility.

Most conventional coal-based power plants are 30 to 35 percent efficient. As a CHP plant, Spiritwood Station is more efficient because it takes advantage of the energy in the steam. In a conventional power plant, that steam is typically released to cooling towers. Since the steam from Spiritwood Station is used as process steam for the adjacent facilities, the plant is 60 to 65 percent efficient.

We have implemented the co-firing of natural gas with coal at Spiritwood Station. This provides both an economic benefit and an environmental benefit. Because natural gas has a lower carbon content per unit of heat content relative to coal, firing natural gas in lieu of coal produces fewer tons of greenhouse gases while producing the same amount of heat and power. Co-firing also allows the boiler to operate at lower steam loads during times of low MISO prices. Given that natural gas prices are expected to continue to be
low for some time, we are currently looking at opportunities to increase the natural gas co-firing capability when economic to do so.

North Dakota Soybean Processors recently announced they are taking steps toward the development of a soybean processing plant near Spiritwood Station that would potentially be a third steam customer for Spiritwood Station. The plant would be an integrated soybean crush facility and refinery, crushing 125,000 bushels of soybeans per day to produce soybean meal, oil and biodiesel. Spiritwood Station’s efficiency will further improve with the addition of a third steam customer.

Spiritwood Station is a reliable combined heat and power resource for our members and supplies process steam to industrial customers. The station provides a hedge against market prices for our load and is fully in compliance with state and federal environmental standards. We expect Spiritwood Station to continue operating well into the future. We have no plans to retire Spiritwood Station.
6 Energy Efficiency

GRE’s portfolio of energy efficiency program offerings is informed by the end uses that are served by our members. Our member’s electric use is dominated by residential consumers, which account for 80 percent of total accounts. However, a significant percentage of overall energy savings achievements are realized by large commercial, industrial and agricultural consumers.

GRE and our members work cooperatively with end users to educate, identify and implement energy efficient technologies that provide both energy and economic benefits. A key strength of our efficiency portfolios are the close relationships that our members have with their end users, which enables a high level of awareness of energy efficiency opportunities and the implementation of cost effective energy efficiency.

6.1 Historic Achievements

Since 2010 GRE’s members have realized combined results that are in excess of the 1.0 percent energy conservation goal that has been set by the Minnesota Legislature. These results are shown in Figure 18 below. The bars represent kilowatt-hour savings achievements while the red line represents percent achievement by year. The blue line represents the Minnesota demand side savings percent goal, or 1.0 percent of demand-side annual retail energy sales.
In 2015, our members’ end users achieved combined energy reductions of 121,000,000 kWh through efficiency savings. Annual Department of Commerce approval letters for our conservation improvement program (CIP) are included in Appendix E.

Figure 19 below illustrates the annual achievements of GRE’s AR members over time relative to the 1.0 percent energy savings goal.
Annual variation in achievements can be expected, especially those reductions made by larger commercial and industrial members which do not always yield a smooth reduction curve.

### 6.2 End-use Members

As shown in Figure 20, GRE’s system is dominated by residential end-use consumers. The majority of our members have residential sales that are in excess of 60 percent of total electricity sales. This characteristic has been reflected in GRE’s energy efficiency program offerings and energy savings achievements. Energy savings from efficient lighting, such as LED lighting, has yielded a sizeable percentage of the total energy savings achievements by all of GRE’s member distribution cooperatives.

*Figure 20 - Member Residential Energy Sales*
6.3 Lighting

Lighting is the primary driver of energy savings within GRE’s energy efficiency portfolio. As shown in Figures 21 and 22, in 2015 GRE and our members realized approximately 53 percent of commercial and industrial energy savings and approximately 10 percent of Residential energy savings from lighting measures that were undertaken by end use members. This is being driven in large part by the reductions in the cost of LED technologies and the wider availability of this technology for end use applications. Currently many of our members are working to change out security lights, street lights and other outdoor lighting applications with LED. The end use benefits of LED lighting go beyond energy savings and include reduced O&M savings and better light quality.
Utility efficiency programs have operated under the assumption that end-use consumers would not choose a lower efficiency product over a higher efficiency product due to the incremental cost that is associated with the higher efficiency product. Policies that pushed utilities to offer incentives were focused on reducing or eliminating the incremental cost of the higher efficiency product. However, the lighting market has changed significantly since the passage of the Federal Energy Independence and Security Act (EISA), which established new standards for general service lighting. Now lights are thought of more as lumens of output rather than the standard 100W, 75W, 60W, 75W, 60W and 40W products of the past. The lighting aisle at most hardware stores has exploded with new products and the prices of LEDs have come down significantly and will continue to do so in the future. Figure 23 from EIA illustrates the dual lighting trends of reduced costs and higher efficiencies over time.

Figure 23 - Reduced Costs and Higher Savings over Time

Most of the primary end uses that comprise major residential electric end uses have been the target of federal efficiency standards over the past several decades. The EISA is one of the most significant efficiency standards that has
impacted energy savings potential. Table 7 illustrates the impact that these standards have had on lighting energy consumption. Essentially, the EISA standards have reduced the energy consumption of each lamp category by a minimum of 28 percent. It is important to note that while these standards improve energy savings overall, the impact of the efficiency standards affects the total savings that can be realized by utility efficiency programs.

Table 7 - EISA Standards Impacts

<table>
<thead>
<tr>
<th>General Service Incandescent Lamps</th>
<th>Maximum</th>
<th>Existing</th>
<th>Percentage</th>
<th>Minimum Rated Lifetime</th>
<th>Effective Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated Lumen Range</td>
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<td>Wattage</td>
<td>Decrease</td>
<td></td>
<td></td>
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<tr>
<td>1490-2600</td>
<td>72</td>
<td>100</td>
<td>28%</td>
<td>1,000</td>
<td>1/1/2012</td>
</tr>
<tr>
<td>1050-1489</td>
<td>53</td>
<td>75</td>
<td>29%</td>
<td>1,000</td>
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<td>750-1049</td>
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<td>28%</td>
<td>1,000</td>
<td>1/1/2014</td>
</tr>
<tr>
<td>310-749</td>
<td>29</td>
<td>40</td>
<td>28%</td>
<td>1,000</td>
<td>1/1/2014</td>
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</tbody>
</table>

6.4 Energy Efficiency Programs

GRE’s energy efficiency programs use an “all of the above” approach to member energy efficiency engagement. The total program is made up of five components:

1. **Equipment Incentive Programs** - These programs provide incentives for our members’ end users to invest in equipment having greater efficiency than equipment that meets current federal standards. Incentives are based on the level of budget and the current commercial state of the technology. As technologies mature and the market for these technologies transform the overall rebate for those technologies will be decreased.
2. **Consumer Behavior Programs** – Consumer behavior programs focus on educating end users about their energy use and providing relevant comparisons that seek to illustrate ways in which the end-use member can reduce their consumption and lower their overall cost of energy. Several of GRE’s members have employed tools like MyMeter which presents energy consumption data through an online web portal, and OPOWER Home Energy Reports, which provide consumers with a report that highlights how their consumption compare to neighbors. In addition, several of our members have employed direct appeals to their end users to reduce their consumption during the hottest months of the year. These “Beat the Peak” programs ask end users to voluntarily reduce their consumption and are associated with contests that reward end users that realize the greatest reduction in their overall electric consumption.

3. **Supply-Side Efficiency Programs** – GRE and our members are leaders in identifying unique ways of improving the efficiency of generation, transmission and distribution of electricity. From the now commercialized DryFine™ process to turbine upgrades, variable-frequency drive (VFD) fan and pump applications, efficiency is often a central focus of our capital planning and improvements to the electric supply and delivery system. These savings have generated at least 0.5 percent of the efficiency goals that have been met by GRE since 2010.

During the planning period we expect to make a major investment in our HVDC system, which will result in supply side energy efficiency improvements.
4. **Market Transformation** – GRE’s long history of efficiency engagement with our members has resulted in end users who are well versed in the benefits associated with investments in efficiency. As the market share of products that carry labels indicating efficient products, e.g. ENERGY STAR®, have expanded, many members have adopted these technologies without taking advantage of rebate programs.

5. **Demand Response** – GRE’s robust demand response efforts are focused on modifying the load curve during the periods of monthly peak demand, as well as ongoing efforts to shift as many end uses to off-peak periods as possible. The effort to shift end uses to off-peak periods is most pronounced in the areas of electric storage water heating and EV charging efforts. More information on our demand response program follows in the next section.

Between 2010 and 2011, GRE worked with EPRI to develop a picture of the energy efficiency resource potential throughout our service territory. This resulted in an analysis of three member sectors: metro and rural residential members and small commercial. These end-use classes became the focal point for energy efficiency analysis due to many of the common electrical end uses that are targeted through our member energy efficiency program efforts. The results of this analysis have been incorporated into the analysis of energy efficiency potential achievements, which has helped us to identify those end uses that offer the greatest potential for energy efficiency investment by end use members.

Ultimately, the analysis by end use continues to provide great insights into the program offerings that are most appropriate for GRE’s member end users. Figures 24 and 25 below show the expected change in energy end uses in the rural residential sector. This analysis assists us in better utilizing the end-use
information that is available from the EIA as well as other information resources that are committed to identifying energy efficiency opportunities throughout the economy.

Figure 24 - Rural End-Use 2009

Figure 25 - Rural End-Use Projected 2030
As can be seen from these figures, the overall share of end-use consumption by all activities is expected to decrease in all areas except for Other Uses, due to the combined impact of changes to codes and standards, as well as ongoing utility efficiency efforts. The category of Other Uses represents a number of plug loads and household entertainment, e.g. game consoles, and network infrastructure, which have not been the focus of many utility programs to date. Furthermore, many of these end uses are impacted by consumer behavior, which requires a multipronged approach to address.

GRE plans the following energy efficiency program activities throughout the Five Year Action Plan:

- Survey members in 2017 regarding key electric end uses within homes and businesses;
- Participate in research to further characterize energy efficiency end use technologies;
- Work with members to identify and market new programs that improve awareness of energy consumption, increase the adoption of efficient end-use technologies where practical, and minimize rate impacts; and
- Further evaluate the efficiency opportunities within our members’ service territories.

While GRE and its members are committed to achieving the energy efficiency goals that have been established by the state of Minnesota, there are a number of challenges that could adversely affect the realization of these savings. Broadly speaking, these challenges fall into several categories:

- Rural, residential nature of GRE’s service territory;
Advancements in codes and standards, which limit both the number of opportunities and the incremental energy benefit associated with those opportunities;

Market transformation of efficient technologies; and

End users investment appetites.

More than 80 percent of GRE members’ end users are rural, residential customers which account for approximately 65 percent of our total energy sales. Today, there are fewer residential energy savings opportunities due to continued improvements to building codes, appliance standards and limited new home construction. Additionally, nearly 80 percent of Minnesota residential cooperative members have income levels below the state average. This limits consumer investment in energy conservation.

A forecast of potential energy savings achievements by member end-use class is shown in Figure 26 below.

Figure 26 - Projected Energy Savings Achievement by Member Class
Energy savings in the Industrial class are expected to grow the most, while growth in the Metro and Rural Residential classes are expected to decline.

GRE is committed to working with our members and their end users to build on their demonstrated past success in achieving energy efficiency savings. Our members will continue to strive to reach total savings and supply-side efficiencies equal to 1.5 percent of total retail energy savings. This will be accomplished by continuing energy savings equivalent to 1.0 percent through member-side activities, while obtaining 0.5 percent in supply side efficiencies throughout our members’ and our systems.

GRE will continue to work with our members to identify the best means to improve efficiency in a manner that is consistent with the established delivery of programs that yields the most cost-effective results.
7 Demand Response

GRE’s demand response (DR) programs intentionally change our members’ end-users electric usage patterns from their normal consumption patterns in response to changes in the price of electricity or incentive payments. The programs are largely designed to induce lower electricity use at times of high wholesale market prices and, if possible, shift the electricity use to times when wholesale market prices are at their lowest, which is normally at nighttime hours. By actively engaging tens of thousands of our members’ end-use consumers, we are able to reduce electric price volatility and the need for additional generation capacity, while enhancing system reliability and member value.

7.1 Demand Response History through Present

GRE has been investing in DR since 1979. The first attempt to alter member consumption was accomplished using a simple time clock which limited a water heater’s consumption to the middle of the night. Today we still invest in technologies that shift member loads. Time clocks were replaced long ago by direct load control technologies which use very high frequency radio waves and paging networks to communicate varying strategies to hundreds of thousands of deployed devices. Now, the next wave of technology tasked with shifting consumption is being installed across our member cooperatives by accompanying their Advanced Metering Infrastructure (AMI) deployment.

Since 1979 GRE and our members have saved hundreds of millions of dollars from joint investment in demand response. As the years go by the dollars saved from DR investments continue to accumulate. In fact, the value of DR is
increasing. The development of wholesale power markets combined with advancements in DR technologies allows utilities to provide more value from DR resources than what was previously possible.

Historically, DR activities were utilized to reduce the peak load for the utility investing in the DR resources. That method of controlling resources is typically referred to as peak shaving. Peak shaving still plays a significant role in the overall value of DR. However, moving forward, we will be focusing more of our DR efforts on controlling for energy pricing, integrating DR into transmission planning considerations, and to enable ancillary service functions.

Methodology
In order to fully take advantage of the benefits of the demand response resource that we have invested in, we and our members typically control loads on summer peak days from 1-10 p.m. This large window of control is necessary as it captures multiple value streams. MISO’s wholesale energy market prices typically peak between 1 p.m. and 4 p.m. Controlling loads between these hours provides a cost savings opportunity as lower cost energy can be purchased later in the day. Between 4 p.m. and 7 p.m. We control loads to reduce the system load or coincident system peak.

Controlling for the system peak reduces our capacity requirements and was the initial incentive that drove investment in DR. Control after 7 p.m. is to avoid setting a new system peak when the loads being controlled are restored. If we release control of the loads at 7:01 p.m., a new system peak may be established from the surge of consumption that would occur due to all the controlled devices resuming the consumption of electricity at the same time. To avoid this rebound peak, control of the appliances is maintained until
enough load is removed from the system due to the natural ramp down of consumption later in the evening hours as shown in Figure 27.

Figure 27 - Historic controlled and uncontrolled hourly load shapes on the day of GRE’s MISO coincident peaks.

Our overall maximum control amount capability is now almost 400 MW, reflecting a 12-year compounded annual growth rate of 1.8 percent. Figure 28 below shows our annual historic DR control amount in megawatts. This reflects our growing ability to reduce our system peak through DR mechanisms.
Our DR efforts have been in four core areas: peak shave water heating, irrigation, cycled air conditioning, and commercial and industrial (C&I) interruptible load, as shown in Figure 29.
7.2 Coincident Peak vs. Uncontrolled Peak

GRE forecasts the monthly coincident peak as opposed to the uncontrolled coincident peak as shown in Figure 30. The monthly coincident peak is the largest metered peak in a given month. The uncontrolled monthly coincident peak is an estimated peak based off of the type and quantity of each DR program: peak shave water heating, irrigation and cycled air-conditioning.

The total embedded DR savings is the area between the estimated uncontrolled coincident peak and the metered coincident peak. This can be clearly seen as the shaded area in green found in Figure 30.

Figure 30 - Controlled and Uncontrolled GRE Coincident Peak and associated demand response terminology.

7.3 Example Demand Response Savings Calculation

On Aug. 3, 2016, GRE’s load control program was called upon between the hour of 3 p.m. and 10 p.m. (Figure 30 and Table 8). The total amount of peak
demand response savings was 194 MW (2,486 MW – 2,292 MW) and 1,996 MWh of energy savings as shown in Table 8.

Table 8 - Controlled and Uncontrolled GRE coincident peak with estimates of control amounts, demand savings, and energy savings.

<table>
<thead>
<tr>
<th>Date</th>
<th>Hour</th>
<th>Temp</th>
<th>Metered Demand</th>
<th>Estimate Uncontrolled Demand</th>
<th>Estimate of Load Control</th>
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7.4 Demand Response Management System

GRE recently installed a modern DR management system: Open Access Technology International, Inc.’s (OATI) webDistribute system. The new system will allow more precise control and allow for interconnection with growing load control technologies, such as smart thermostats and Wi-Fi-enabled devices.
With two-way communication, we will be able to accurately monitor the effectiveness of our DR efforts, including water heaters, pumps, space heaters, ETS devices, EV chargers, and distributed energy resources for member-owned generators and to analyze data to continually improve our programs. We can manually create and schedule events, or events can be triggered automatically based on time-of-day or system conditions. OATI webDistribute provides after-the-fact performance reporting for the overall system or each member-based on metering data. We are beginning to transition existing demand response programs to this new system. The system will then be made available to our members, who can benefit from the system’s additional capabilities. OATI has previously supplied GRE with OATI webCompliance, which helps us proactively improve overall efficiency and reliability.
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8 Forecasts

GRE is a 28 member G&T cooperative, with 20 of our members being All Requirements (AR) and eight being Fixed (Fixed) or partial requirements. The AR members purchase all of their demand and energy needs from us, with the limited exception of the five percent option, as described in Section 3. Fixed members purchase a fixed amount of capacity and energy from us then purchase their remaining energy and capacity needs from another power supply provider.

8.1 Forecast Development

Residential end use consumers account for 56 percent of energy sales. This is the customer class that most influences our forecasts. To determine the residential expected energy and demand, we conduct econometric modeling of residential member growth, using an outside consultant to develop the residential end use forecasts for our AR members. We then determine the associated DC line losses, transmission losses, known future energy and demand additions and subtractions, and then add the Fixed member requirements to create our GRE system energy and demand forecasts.

The AR member energy and demand econometric forecasts are developed using metered data with historic load control embedded in the data. An assumption is made that our historic growth in energy efficiency and demand response programs will continue to be the same going forward.

Due to the geographic and economic diversity of GRE’s membership, the 20 AR members are broken into three distinct forecast regions: Metro Region,
Northern Region, and Southern & Western Region. By evaluating the geographic diversity of the AR member needs in these three distinct regions, we can incorporate differences in the forecast input variables of regional weather, air conditioning saturation, space and water heating fuel type, and localized econometrics.

8.2 Forecast Results

Our energy forecast produces a five year compounded annual growth rate (CAGR) of 0.92 percent. The 10 and 20 year CAGR are both 1.34 percent. The five-year CAGR is lower because our power contract with Elk River Municipal Utilities (ERMU) expires in 2019. Figure 31 depicts our energy forecast, including a high and low sensitivity forecast, which were generated as plus and minus two standard deviations around the expected value.

*Figure 31 - GRE Energy Forecast with High and Low Growth*
Great River Energy

2017 Integrated Resource Plan

Table 9 presents the energy forecast values over the planning period.

Table 9 - 2018 - 2032 Energy Forecast

<table>
<thead>
<tr>
<th>Year</th>
<th>50/50 All Requirement Member Forecast (+)</th>
<th>Elk River Municipal (-)*</th>
<th>DC Line Losses (+)</th>
<th>Transmission Losses (+)</th>
<th>Alliant Load Southern Coops Forecasts (+)</th>
<th>Fixed Member Requirements (+)</th>
<th>Dakota Spirit Ag Forecasts (+)</th>
<th>Energy Requirement Forecast (MWh)</th>
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<td>2,204,931</td>
<td>41,600</td>
<td>15,904,845</td>
</tr>
</tbody>
</table>

* All Forecasts share these components regardless of sensitivities
** Five-year CAGR is impacted with the loss of Elk River Municipal in 2019.

- 5-Year CAGR** 0.93%
- 10-Year CAGR 1.34%
- 15-Year CAGR 1.34%

The primary drivers of the demand and energy growth in the forecasts are the increasing numbers of residential consumers in the Metro and Southern & Western areas, and a shift from seasonal homes to year-round homes in the Northern region.

GRE’s demand forecast produces a five-year CAGR of 0.59 percent. The 10 and 20 year CAGRs are 0.99 percent and 1.04 percent, respectively. As with the energy forecast, the demand forecast growth rate is impacted by the ERMU load leaving our system in 2019. Figure 32 below shows the demand forecast with the high and low sensitivities as evaluated in our planning process, which reflect two standard deviations around the expected value.
Table 10 presents the demand forecast values over the planning period.

Table 10 - 2018 - 2032 Demand Forecast
Additional forecast sensitivities were developed for the capacity expansion modeling to investigate increased levels of conservation and efficiency, customer-owned distributed generation, and customer-owned EVs.

For the energy efficiency sensitivities, we evaluated the impact of 1.75, 2.0, and 2.5 percent of total member sales on the forecasts. These sensitivities are part of the conservation analysis in Appendix F.

8.3 Southern Minnesota Energy Cooperative

Southern Minnesota Energy Cooperative (SMEC) was formed in 2013 by 12 electric distribution cooperatives as a single point of contact for the proposed purchase of Alliant Energy’s electric service territory in southern Minnesota. SMEC members who are also members of GRE are:

- BENCO Electric Cooperative (AR),
- Brown County Rural Electrical Association (AR),
- Federated Rural Electric (Fixed),
- Minnesota Valley Electric Cooperative (Fixed),
- Nobles Cooperative Electric (AR),
- Redwood Electric Cooperative (Fixed),
- South Central Electric Association (Fixed),
- Steele-Waseca Cooperative Electric (AR)

Four of the 12 members of SMEC are AR members of GRE. SMEC’s purchase agreement with Alliant provides that Alliant will be the power supplier to the load SMEC purchased from Alliant. The four AR members who are members of SMEC have agreed that GRE will supply their respective portions of the load
acquired from Alliant starting in 2025. This is expected to increase our demand forecast by approximately 27 MW and our energy requirement forecast by approximately 182,190 MWh. These demand and energy requirements are included in our demand and energy forecasts.

See Appendix D for further analysis of our energy and demand forecasts.
9 Plan Development

The overarching goal of our planning process is to identify a resource plan that will meet our members’ future energy and capacity needs at low cost, while retaining flexibility to navigate in an evolving industry. As we move through this planning process, we take stock of where we have been, assess where we are today, and project where we are headed in the future.

The planning process—and the future vision of the portfolio we present here—is shaped by our strategies, regulatory and legislative requirements, environmental policy, Commission feedback from previous IRP filings, and stakeholder input. The process begins with data and information gathering and then proceeds to forecasting and capacity expansion modeling, the results of which inform the selection of our Preferred Plan.

GRE developed this resource plan using the following planning process:

- Engage interested stakeholders;
- Determine modeling assumptions and requirements;
- Evaluate conservation and energy efficiency potentials;
- Develop econometric energy and load forecasts to determine growth for our AR members;
- Develop system energy and demand requirements using the AR forecasts and adding in Fixed member requirements, transformation and transmission losses, DC line losses, and known future additions or subtractions;
- Develop our load and capability position;
- Identify regulatory and legislative requirements, including externalities and regulatory costs;
Model scenarios that include sensitivities to identify potential expansion plans using a capacity expansion plan optimization model;

Develop an Expected Values Case and a Reference Case;

Evaluate reliability, costs, environmental impacts, and risks of different expansion plans;

Identify a Preferred Plan that meets our members’ needs while complying with all regulatory and legislative requirements; and

Evaluate the impact of key sensitivities on the Preferred Plan to ensure robustness of result across numerous assumptions and sensitivities.

The resources established in the Preferred Plan include wind additions in the early 2020s. Additional wind resources were identified as needed in the late 2020s. No other new resource additions are included in the planning period. No existing generation retirements are included in the planning period. The Preferred Plan identified in our planning process balances the objectives of cost-effectiveness, reliable service, environmental stewardship, and regulatory compliance.

The following sections discuss the modeling and results underlying the development of the Preferred Plan.

**9.1 Modeling Overview**

GRE member future demand and energy needs underpin Preferred Plan. The result of the forecasting process is an aggregate 15-year, hourly load profile. The impacts of existing energy efficiency and conservation programs are embedded in this forecast. Several sensitivities were modeled to reflect the potential of higher levels of energy savings. These sensitivities likewise net energy savings from the hourly load profile at total savings levels of 1.75%, 2%
and 2.5% per year. The annual costs for achieving the additional savings were added to each year of the plan costs, and discounted back to the base year of the study to produce a net present value of revenue requirements (NPVRR) inclusive of savings costs. Additional details on the forecasting process and the energy savings scenarios and costs we considered can be found in Appendix D and Appendix F, respectively. The load profile, adjusted for energy efficiency and conservation, is a key input into the modeling portion of the planning process.

Within the capacity expansion model, a diversity factor was applied to the load profile to reflect the diversity between GRE’s system summer peak and MISO’s summer peak. MISO considers the months of June, July, August, and September as the timeframe for identifying the summer coincident peak. The diversity factor was developed for our 2014 IRP filing through analysis of observed summer load diversity from 2005 through 2012. As a result of that analysis, we use a 10 percent diversity factor to represent the difference between GRE’s summer system peak and MISO’s summer system peak.

Long-term resource portfolio optimization modeling was then carried out, with inputs from the forecasting process and other sources. A range of potential market conditions, technological advancements, and future policy and regulatory developments were modeled to test expansion plans for robustness. The cost of each expansion plan, which is represented in terms of the net present value of revenue requirements (PVRR), is one of several factors in plan evaluation and eventual selection of the Preferred Plan.
9.2 Capacity Expansion Model

We use an ABB product called System Optimizer (SO) for our capacity expansion modeling. SO is a long-term resource forecasting model that determines the optimal type, timing, and amount of resource additions and/or retirements, for a given study horizon and footprint. The objective function of SO is the minimization of total system costs, subject to user-defined constraints, including load and planning reserve margin requirements.

SO uses either a Linear Programming (LP) or Mixed Integer Programming (MIP) solution methodology to optimize the resource portfolio, depending on run execution settings. The output of the LP/MIP solution is a single, optimal expansion plan. Other common industry capacity expansion models may employ a Dynamic Programming solution methodology, which produces both optimal and sub-optimal plans for evaluation by the user. Both are considered acceptable methods to support the development of long-term resource plans.

SO employs a representative hours approach to categorize and simplify analysis of temporally granular data (e.g., hourly) across a lengthy study period (e.g., 15 years). The user can determine how the model will chunk hours across each day (e.g., peak from HE7 to HE22) and days across each week (e.g., peak day, average day, weekend day). Representative weeks are formed for each calendar month and then scaled up based on the number of days per month.

End effects—or the impact of capital investment costs that would occur beyond the study horizon—are addressed in SO by the application of real level annual capital recovery factors. This means that the SO optimization algorithm will not discriminate against high-capital investments versus low-capital investments in the out-years of the study; it will only account for the capital recovery that
would occur within the study period and will compare this cost against competing investments (e.g., the cost of a PPA).

At a high-level, data inputs for SO include the load profile, existing and potential resources, physical and financial resource characteristics including emission rates, system constraints, market proxies and representation of environmental policies and/or regulations. SO also allows for limited representation of transfer capability on the transmission system, as well as transmission contracts/rights. We have historically elected not to represent transmission infrastructure and contracts/rights in SO; there are other long-term planning models used by GRE that are better-suited to inform transmission planning.

Key outputs of SO simulation include the optimal expansion plan, present value of revenue requirements (system cost), station performance and costs, and emissions. The highest level of temporal detail for SO outputs is monthly.

See Figure 33 below for additional details on inputs and outputs for SO.
While SO is an appropriate tool to support long-term planning, there are tradeoffs in using it, as with any model. Certain aspects of market interaction, risk, and additional resource costs and value streams are not captured in GRE’s SO model, as shown in Figure 34.
9.3 Modeling Methodology

GRE’s approach to modeling for the 2017 IRP can be broken down into the following high-level steps:

- Identify regulatory and legislative requirements to be considered in the modeling process and/or represented in the model.
- Develop modeling assumptions for the Expected Values Case.
- Identify a draft list of sensitivities.
- Develop modeling assumptions for draft sensitivities.
- Incorporate feedback from internal and external parties on the Expected Values case, modeling assumptions, and sensitivities.
- Build the model.
Submit a test run of the Expected Values Case and perform a quality control check on the results.

Submit test runs of the sensitivity cases and perform a quality control check on the results.

Troubleshoot and update the model as needed; re-submit the test runs; iterate as needed until results pass a quality control check.

Adjust the run list, if/as needed, and perform any additional testing.

Compile the results and evaluate them in terms of reliability, cost, environmental impacts, and risk.

Identify a Preferred Plan that meets GRE member needs while complying with all regulatory and legislative requirements.

Perform additional testing on the Preferred Plan if/as needed

Compile and evaluate final results.

Aside from testing runs, the Mixed Integer Programming (MIP) solution methodology is used to identify optimal plans. SO run execution settings, such as the relative MIP gap tolerance, follow vendor recommendations. Tunnel constraints, or upper bounds on new resource additions, are tested and balanced with real-world feasibility.

The Expected Values Case represents a collection of foundational expected assumptions. These include existing policies and regulations, moderate commodity and market forecasts, and a 50/50 energy and demand forecast. Current industry projections for potential resource availability, cost and operating characteristics are utilized.

The Reference Case is the Expected Values Case plus externalities and the future cost of carbon dioxide, following Minnesota’s planning requirements. Numerous sensitivities were run off of both the Expected Values Case and the Reference Case. Most were driven by assumptions for reasonable low and high
bounds around key modeling variables. Others were driven by Commission Order or by stakeholder request. Table 11 reflects the sensitivities conducted in the modeling.

Table 11 - Modeling Variables and Definitions

<table>
<thead>
<tr>
<th>Variable</th>
<th>Expected Values Case &amp; Sensitivities</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand &amp; Energy (D&amp;E)</td>
<td>Low</td>
<td>$12/30 Forecast</td>
</tr>
<tr>
<td></td>
<td>Expected Values</td>
<td>$12/50 Forecast</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>$9/10 Forecast</td>
</tr>
<tr>
<td>Minnesota Hub Locational Marginal Price (Market Prices)</td>
<td>Low</td>
<td>Expected Values - 20%</td>
</tr>
<tr>
<td></td>
<td>Expected Values</td>
<td>ACEs short-run marginal cost curve for Minn Hub; monthly peak and off-peak values</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>Expected Values +20%</td>
</tr>
<tr>
<td>Gas Price</td>
<td>Low</td>
<td>Expected Values - 10%</td>
</tr>
<tr>
<td></td>
<td>Expected Values</td>
<td>ACEs Ventura Hub (delivered) forward curve; monthly values</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>Expected Values +50%</td>
</tr>
<tr>
<td>Coal Price</td>
<td>Low</td>
<td>Expected Values - 10%</td>
</tr>
<tr>
<td></td>
<td>Expected Values</td>
<td>Internal GRE forecast</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>Expected Values +25%</td>
</tr>
<tr>
<td>Coal Creek Station Retirement (CCS Retire)</td>
<td>Expected Values</td>
<td>No forced CCS retirement</td>
</tr>
<tr>
<td></td>
<td>2020</td>
<td>CCS shut down in 2020</td>
</tr>
<tr>
<td></td>
<td>2024</td>
<td>CCS shut down in 2024</td>
</tr>
<tr>
<td></td>
<td>2028</td>
<td>CCS shut down in 2028</td>
</tr>
<tr>
<td></td>
<td>2030</td>
<td>CCS shut down in 2030</td>
</tr>
<tr>
<td></td>
<td>Optional Decommissioning</td>
<td>The model is allowed to select CCS for retirement in any year; shutdown costs incl.</td>
</tr>
<tr>
<td>Market Interaction &amp; Planning Reserve Margin Requirement (Market Purchase Cap)</td>
<td>10%</td>
<td>Market Purchases Capped at 10% of load, indexed hourly/7.8% PRMR</td>
</tr>
<tr>
<td></td>
<td>30%</td>
<td>Market Purchases Capped at 30% of load, indexed hourly/7.8% PRMR</td>
</tr>
<tr>
<td></td>
<td>40%</td>
<td>Market Purchases Capped at 40% of load, indexed hourly/7.8% PRMR</td>
</tr>
<tr>
<td></td>
<td>G&amp;E Standalone System /Market Off</td>
<td>No Market interaction/15% PRMR</td>
</tr>
<tr>
<td>Solar Costs</td>
<td>5% De-Escalation</td>
<td>Expected Values with 0.0% annual de-escalation in solar costs for first 10 years; no escalation for the last 5 years</td>
</tr>
<tr>
<td></td>
<td>2.5% De-Escalation</td>
<td>Expected Values with 2.5% annual de-escalation in solar costs for first 10 years; 0% escalation for the last 5 years</td>
</tr>
<tr>
<td></td>
<td>Earlier Solar PPA</td>
<td>Solar PPA first available in 2018 (compared to 2020 in Expected Values Case)</td>
</tr>
<tr>
<td></td>
<td>Expected Values</td>
<td>2016 EIA AEO projections for self-build potential solar PV; vendor quotes for PPAs</td>
</tr>
<tr>
<td>Wind Costs</td>
<td>$25/MWh Wind PPA</td>
<td>$25/MWh Wind PPA, available starting in 2018, fixed cost for 15-year study period</td>
</tr>
<tr>
<td></td>
<td>Earlier/Chaper Wind PPA</td>
<td>$26/MWh Wind PPA, available starting in 2018, 2.5% annual escalation of contract costs</td>
</tr>
<tr>
<td></td>
<td>Expected Values</td>
<td>2016 EIA AEO for self-build wind; vendor quotes for PPAs</td>
</tr>
<tr>
<td></td>
<td>10/MWh Wind Dispatch Adder</td>
<td>V&amp;O adder for new wind resources only; proxy for mid-level wind-weighted LMPs</td>
</tr>
<tr>
<td></td>
<td>15/MWh Wind Dispatch Adder</td>
<td>V&amp;O adder for new wind resources only; proxy for high-level wind-weighted LMPs</td>
</tr>
<tr>
<td>CO2 Allowance Prices</td>
<td>Expected Values</td>
<td>No CO2 Allowance Price</td>
</tr>
<tr>
<td></td>
<td>50/ton</td>
<td>55/ton CO2 dispatch adder</td>
</tr>
<tr>
<td></td>
<td>120/ton</td>
<td>$10/ton CO2 dispatch adder</td>
</tr>
<tr>
<td>Externalities</td>
<td>Expected Values</td>
<td>No externalities applied</td>
</tr>
<tr>
<td></td>
<td>Low-Ext</td>
<td>min externalities applied</td>
</tr>
<tr>
<td></td>
<td>Mid-Ext (Reference Case)</td>
<td>average of min/max externalities applied</td>
</tr>
<tr>
<td></td>
<td>High-Ext</td>
<td>max externalities applied</td>
</tr>
<tr>
<td>Minnesota Renewable Energy Standard</td>
<td>Expected Values</td>
<td>No RES constraint modeled (RES is projected to be met by Expected Values fleet beyond IRP study horizon)</td>
</tr>
<tr>
<td>Demand-Side Management (DSM)</td>
<td>Expected Values</td>
<td>1.50% total (1.5% demand-side, currently embedded in D&amp;E forecast; 0.5% supply-side)</td>
</tr>
<tr>
<td></td>
<td>1.50%</td>
<td>1.75% total (1.25% demand-side, embedded in D&amp;E forecast; 0.5% supply-side)</td>
</tr>
<tr>
<td></td>
<td>2.00%</td>
<td>2.00% total (1.5% demand-side, embedded in D&amp;E forecast; 0.5% supply-side)</td>
</tr>
<tr>
<td>Distributed Generation (DG)</td>
<td>Expected Values</td>
<td>N/A, Expected Values runs do not include explicit DG modeling</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>Projected increase of residential solar expansion</td>
</tr>
<tr>
<td>Electric Vehicles (EV)</td>
<td>Expected Values</td>
<td>N/A, Expected Values runs do not include explicit EV assumptions</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>~9% penetration by 2030</td>
</tr>
</tbody>
</table>

The majority of cases run off the Expected Values or Reference Case involved changing only one variable, to isolate the impact of that variable on the results. A handful of cases involved changing a combination of variables, for
analysis of interactions between key variables. In total, 65 sensitivities were modeled around either the Expected Values Case or the Reference Case. See Table 12 for the complete run list.

Table 12 - Run List

<table>
<thead>
<tr>
<th>Run List</th>
<th>Run List Continued</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected Values</td>
<td>Reference Case +</td>
</tr>
<tr>
<td>Gas - Low Prices</td>
<td>Expected Values</td>
</tr>
<tr>
<td>Gas - High Prices</td>
<td>Market - Low Prices</td>
</tr>
<tr>
<td>Coal - Low Prices</td>
<td>Market - High Prices</td>
</tr>
<tr>
<td>Coal - High Prices</td>
<td>Market Purchases Cap - 30%</td>
</tr>
<tr>
<td>Market - Low Prices</td>
<td>D&amp;E - Low (10/90 Forecast)</td>
</tr>
<tr>
<td>Market - High Prices</td>
<td>D&amp;E - High (90/10 Forecast)</td>
</tr>
<tr>
<td>D&amp;E - Low (10/90 Forecast)</td>
<td>Solar - 5.0% De-Esc</td>
</tr>
<tr>
<td>D&amp;E - High (90/10 Forecast)</td>
<td>Wind - $15/MWh Wind Dispatch Adder</td>
</tr>
<tr>
<td>Zero Growth Load</td>
<td>Solar - 5.0% De-Esc + Wind - $15/MWh Wind Dispatch Adder</td>
</tr>
<tr>
<td>Gas - Low Prices, D&amp;E - High</td>
<td>E/C PPAs</td>
</tr>
<tr>
<td>Gas - High Prices, D&amp;E - High</td>
<td>$25/MWh Wind PPA</td>
</tr>
<tr>
<td>Solar - 2.5% De-Esc</td>
<td>High DG</td>
</tr>
<tr>
<td>Solar - 5.0% De-Esc</td>
<td>High EV</td>
</tr>
<tr>
<td>Wind - $10/MWh Wind Dispatch Adder</td>
<td>Optional Decommissioning Allowed for CCS 1 and 2</td>
</tr>
<tr>
<td>Wind - $15/MWh Wind Dispatch Adder</td>
<td></td>
</tr>
<tr>
<td>Solar - 2.5% De-Esc + Wind - $10/MWh Wind Dispatch Adder</td>
<td></td>
</tr>
<tr>
<td>Solar - 5.0% De-Esc + Wind - $15/MWh Wind Dispatch Adder</td>
<td></td>
</tr>
<tr>
<td>High DG</td>
<td>2020</td>
</tr>
<tr>
<td>High EV</td>
<td>2024</td>
</tr>
<tr>
<td>DSM - 1.25%</td>
<td>2028</td>
</tr>
<tr>
<td>DSM - 1.5%</td>
<td>2030</td>
</tr>
<tr>
<td>DSM - 2.0%</td>
<td>2030</td>
</tr>
<tr>
<td>D&amp;E - High DG + High EV</td>
<td></td>
</tr>
<tr>
<td>CO₂ - $5/ton Dispatch Adder</td>
<td></td>
</tr>
<tr>
<td>CO₂ - $10/ton Dispatch Adder</td>
<td></td>
</tr>
<tr>
<td>CO₂ - $15/ton Dispatch Adder</td>
<td></td>
</tr>
<tr>
<td>Externalities - Low</td>
<td></td>
</tr>
<tr>
<td>Externalities - High</td>
<td></td>
</tr>
<tr>
<td>Standalone GRE System/Market Off</td>
<td></td>
</tr>
<tr>
<td>Market Purchase Cap - 10%</td>
<td></td>
</tr>
<tr>
<td>Market Purchase Cap - 30%</td>
<td></td>
</tr>
<tr>
<td>Market Purchase Cap - 40%</td>
<td></td>
</tr>
<tr>
<td>Optional Decommissioning Allowed for CCS 1 and 2</td>
<td></td>
</tr>
</tbody>
</table>

### 9.4 Modeling Results

Key results evaluated per run include total system cost, or present value of revenue requirements, and expansion plan composition and timing.
9.4.1 Present Value of Revenue Requirements

The PVRR across all cases ranged between $6B and $10B, with the Expected Values Case coming in at $6.9B and the Reference Case at $8.5B. Of the 19 cases with a PVRR greater than $8B, only three were not based off the Reference Case (i.e., only three did not include mid-level externalities and the Future Cost of CO\(_2\)).

The biggest drivers for high system costs, in the form of PVRR, were:

- Externalities/Future Cost of CO\(_2\),
- Forced retirement of Coal Creek Station, and
- A high demand and energy profile (90/10 forecast).

At the other end of the spectrum, optionality of a $25/MWh wind PPA in all years of the study dropped total system costs between $250M and $1.2B, when compared to the equivalent Expected Values Case. The $25/MWh wind PPA assumption was modeled to capture a stakeholder group recommendation for low-cost wind PPAs. We think our Expected Case assumption has a higher likelihood of occurring, given the gradual rollback of the production tax credit for wind, as well as vendor quotes.

Zero load growth and low demand and energy assumptions also resulted in low-to mid-$6B PVRR, driving total system costs down moderately (though not proportionate to cost increases driven by high demand). PVRR for all runs are presented in Figure 35. In the figure, blue bars mark the Expected Values Case and associated sensitivities and yellow bars mark the Reference Case and associated sensitivities.
While absolute PVRR values provide context and a check on reasonability of results, they should not be interpreted as total costs for GRE. As discussed earlier, there are many costs and revenues that are not captured by the SO
model. For purposes of identification of a Preferred Plan, we are more interested in the key modeling variables that are driving cost and the cost deltas among cases.

9.4.2 Expansion Plans

Each run executed in SO produces an optimal expansion plan that details the type, timing and amount of resources added to the system. Resources are added for one of several reasons:

- There are capacity needs that are not being met by the existing resource mix, and/or
- There are energy needs that are not being met by the existing resource mix, or
- Capacity and energy needs are met, but the economics of the energy production of a new resource outweighs the cost of the new resource.

The resources added to the system are dictated in part by user definition. For example if the user only defines combined cycle units (CC) and wind PPAs as resource expansion options, the expansion plan is limited to only CCs and wind PPAs.

The potential resource options in our model include:

- Wind and solar PPAs
- Self-build wind and solar
- Natural gas-fired reciprocating internal combustion engines
- Natural gas-fired simple cycle stations
- Natural-gas fired combined cycle stations
Potential resource additions are further dictated by user settings for the first year in which the resource could be selected for expansion by the model, as well as the maximum number of stations that could be built per resource type per year and per study period. This allows the user to model real world expectations for project timelines or production bottlenecks, for example. See Appendix C for first-year available and maximum stations per year settings.

SO also allows the user to allow or force additions or retirements of resources. In the Coal Creek Station retirement sensitivities, we allowed the model to retire Coal Creek Station if economic to do so. The model did not select the station to be retired. We then forced the model to retire Coal Creek Station units 1 and 2 on Jan. 1 of the year of retirement. These Coal Creek Station retirement sensitivities were conducted because of the 2014 IRP Commission Order to evaluate coal generation retirements. GRE does not plan to retire Coal Creek Station. There are no runs in which we have forced resource additions.

Figure 36 shows the annual and total nameplate capacity expansion per run, illustrating the difference in capacity value across potential resource additions. The different shadings of blue reflect the amounts of nameplate capacity that are added with the deepest blue reflecting the highest number of megawatts added.
The expansion plans for the Expected Values Case and the Reference Case vary significantly. The Expected Values Case includes 600 MW of wind PPAs in the
later years of the study period, whereas the Reference Case plan includes more than 2,000 MW of nameplate wind PPA additions, with the majority of those additions coming on in the early 2020s.

The delta in the wind additions between the Expected Values Case and the Reference Case is driven by economics. The early-year wind additions in the Reference Case are driven by the delta between the cost of energy from wind PPAs and the increased cost of energy production at Coal Creek Station, due to the Future Cost of CO\(_2\) dispatch adder (per Minnesota planning requirements), which goes into effect in 2022. The dispatch adder starts in the mid-$20 range and escalates over time. It is applied to all CO\(_2\) emissions. Upon implementation, it depresses the dispatch of Coal Creek Station down to its minimum loading block.

It is worth mentioning that dump energy (energy production greater than GRE system energy needs at any given time in the model) cannot be factored into the optimization decision. In other words, there is no option to apply a dump energy penalty factor. Our current approach to modeling wind energy is to set wind stations as must run. The wind energy production profile is forced into the model as a proxy for real world market interactions. Most wind resources can submit a very low or even negative offer into market, in large part due to zero fuel costs and the production tax credit. Wind units are rarely priced out of the merit order dispatch stack, and this means they are essentially must run stations.

Dump energy in the model can be thought of as a proxy for high wind production in high wind resource penetration areas, and subsequent suppression of locational marginal prices (LMPs) at the wind node in the real world. With the exception of two sensitivities in which we have attempted to
roughly approximate real-world costs ($10/MWh and $15/MWh wind dispatch adders), this aspect of wind resource economics is not captured in the capacity expansion model. It is one of many factors considered when planning for future resource additions.

In running sensitivities off of the Expected Values Case and the Reference Case, we saw four prevalent trends in the expansion plan results:

1. Small to moderate out-year wind PPA additions.
3. Large early-year wind PPA additions.
4. All-of-the-above capacity additions to fill the gap left by forced Coal Creek Station retirement.

The **small to moderate out-year wind PPA additions** are largely the Expected Case sensitivities. These include runs in which the market purchase cap or market price forecast were varied, runs with demand and energy profiles below the 50/50 forecast (i.e., Zero Load Growth, Low demand and energy, all DSM sensitivities and High DG) or only slightly above the 50/50 forecast (High EV), runs with low price forecasts (market prices, gas price, coal price), and runs with a wind dispatch cost adder. In general, these runs indicate that minimal resource additions are justified before the 10-year mark.

The **second bucket of expansion plan results**—those with **base-year additions of RICEs**—are driven solely by the immediate increase in demand and energy due to the High D&E (90/10) forecast. The delta in 2018 peak demand from the Base D&E profile to the High D&E profile is more than 400 MW, creating an immediate shortfall in the Planning Reserve Margin. RICEs are selected by the
model to fulfill this need because they are the only resource option available in
2018. However, we project that it would likely not be feasible, based on
industry experience to-date, to secure and implement any of the other
potential resource options in a sub-year timeframe. RICE resources could also
be considered a proxy for bilateral contracts, which could offer bridge capacity
or energy.

The third grouping, with large, early-year wind additions, are predominantly
Reference Case sensitivities. The exceptions are the two Expected Values Case
runs with $10/ton and $15/ton CO\textsubscript{2} dispatch adders. The driver for these large
additions of wind PPAs in the early 2020s is the cost of CO\textsubscript{2} emissions
embedded in the externality assumption.

The last bucket of expansion plans are those in which Coal Creek Station is
forced to retire. In each of the four years examined for retirement—2020,
2024, 2028 and 2030—the model selects a combination of gas, wind and solar
resources.

Finally, the results of the two runs in which the model was allowed to
economically retire Coal Creek Station showed that Coal Creek Station is not
economic to retire under expected case circumstances. The application of mid-
level externalities resulted in the retirement of Coal Creek 2 in 2022, driven by
the introduction of the Future Cost of CO\textsubscript{2}. We do not consider the Future Cost
of CO\textsubscript{2} to be part of an expected values future.

For a discussion on the capacity expansion modeling CO\textsubscript{2} emissions results,
please see Appendix L.
9.4.3 The Preferred Plan

After consideration of the modeling results, the Preferred Plan was identified as shown in Table 13 below. The plan PVRR totals $6.886B and includes no resource additions in the five-year outlook, beyond those already planned. In the later years of the study period, 600 MW of new wind PPAs are added to continue to meet member capacity and energy needs in a cost-effective and reliable manner.

Table 13 - GRE’s Preferred Plan

<table>
<thead>
<tr>
<th>Year</th>
<th>Capacity</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>-189</td>
<td>Stanton Station Retirement</td>
</tr>
<tr>
<td>2018</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>300</td>
<td>Wind Power Purchase Agreement</td>
</tr>
<tr>
<td>2021</td>
<td>100</td>
<td>Wind Power Purchase Agreement</td>
</tr>
<tr>
<td>2022</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td></td>
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<td>2028</td>
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<tr>
<td>2029</td>
<td>100</td>
<td>Wind Power Purchase Agreement</td>
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<tr>
<td>2030</td>
<td>100</td>
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<tr>
<td>2031</td>
<td>200</td>
<td>Wind Power Purchase Agreement</td>
</tr>
<tr>
<td>2032</td>
<td>200</td>
<td>Wind Power Purchase Agreement</td>
</tr>
</tbody>
</table>

A range of sensitivities run off the Expected Values Case provides insight into the robustness of the Preferred Plan. Examination of the expansion plan results show that late-year additions of wind resources would economically meet energy and capacity needs for a range of future changes in market conditions.
If significant growth in demand and energy occurred in the near-term, additional resources beyond the Preferred Plan would be needed; however, it is very likely that both spot-load additions and gradual increases in the load would allow sufficient time to acquire additional resources. Likewise, if load growth doesn’t materialize in coming years, the Preferred Plan doesn’t commit GRE and its members to inflexible, long-term capital investments.

Results of the modeling of the Preferred Plan show a significant increase of renewable energy capacity and energy in our portfolio in 2032. Our expected capacity and energy mixes for 2032 are reflected in Figures 37 and 38 below, respectively.

Per the modeling results, the proportion of energy from market purchases in 2032 is eight percent. Based on past experience and recent enhancements to
operations at Coal Creek Station, we anticipate that the proportion of energy coming from coal will decrease and the reliance upon the market for energy needs will increase in the future.

Market interactions can be difficult to capture in the capacity model, given the use of a static market price forecast and the limited ability to represent hourly and daily market interactions. While the model allows for proxy market purchases and sales, these are highly depending upon the market price forecast. This projection of increased market purchases in the future is contingent in part upon market conditions. We will continue to evaluate long-term market prices and to consider cost-effective market purchases for our members.

Figure 39 below illustrates what we believe to be a likely energy fuel type mix in 2032 as a result of Coal Creek Station’ flexible operations, lower minimum load requirements, increased ramping and increased market purchases. These changes are not captured in the model.

Figure 39 - 2032 Potential Energy Fuel Mix with Coal Creek Station Flexible Operation
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10 Legislative and Regulatory Compliance

10.1 Minnesota Renewable Energy Standard Compliance

MN §216B.1691 Subd. 3 states:

(a) Each electric utility shall report on its plans, activities, and progress with regard to the objectives and standards of this section in its filings under section 216B.2422 or in a separate report submitted to the commission every two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section. In its resource plan or a separate report, each electric utility shall provide a description of:

(1) the status of the utility's renewable energy mix relative to the objective and standards;
(2) efforts taken to meet the objective and standards;
(3) any obstacles encountered or anticipated in meeting the objective or standards; and
(4) potential solutions to the obstacles.

Below GRE responds to the points of the statutory requirements:

(1) The status of the utility's renewable energy mix relative to the objective and standards

GRE is in compliance with Minnesota’s renewable energy requirements in Minn. Stat. §216B.1691 (MN RES). The MN RES requires Minnesota utilities to provide
renewable energy equivalent to a progressively increasing percent of retail energy sales culminating in 25 percent by the year 2025. To demonstrate compliance, we utilized the Midwest Renewable Energy Tracking System (M-RETS). Based on the expected load forecast and resource availability, we are and will continue to be in compliance throughout the planning period.

(2) Efforts taken to meet the objective and standards

Current sources of Renewable Energy Credits (REC) include self-generated renewable energy from our waste to energy plant in Elk River, purchased qualifying renewable energy from wind, bio-gas, and small hydro facilities, and market REC purchases. In addition, Fixed members supply GRE with RECs to cover their retail energy sales above GRE’s fixed energy supply obligations to them to ensure they are in full RES compliance.

In calculating the Minnesota retail energy sales basis, GRE subtracts transmission and distribution losses from the amount of wholesale sales to members and wholesales sales to a municipal customer to estimate retail sales attributable to us. We also subtract member retail sales supplied by the Western Area Power Administration by direct contract with the members, retail sales outside of Minnesota, and Fixed members’ supplemental RECs.

Once the retail sales subject to the MN RES have been determined and the required number of RECs to meet the MN RES calculated, we add 100 percent of any Green Pricing (Wellspring) sales by our members to ensure we have sufficient renewable energy to meet all renewable energy requirements.

GRE tracks our renewable compliance on a year-by-year and projected basis. Figure 40 illustrates GRE’s availability of RECs compared with the MN RES requirement. The RECs used for compliance are depicted in the columns, while
the requirements are depicted by the red line. We have and will continue to provide annual MN RES compliance filings to the Commission.

Figure 40 - MN RES Compliance Projections

![Projected Compliance with MN RES of 25% by 2025*](image)

*Graphic reflects REC accounting for All Requirements Members only; 4-year REC banking is assumed

On June 1, 2016, Great River Energy (GRE) submitted a Renewable Energy Certificate Retirement and Reporting for Compliance Year 2015 filing – Docket Number E-999/PR-16-12. We are in compliance with the MN RES. We have since contracted with additional renewable resources to remain ahead of these requirements, and as a result, we have sufficient renewable resources in place to meet the MN RES through the planning period.

(3) Any obstacles encountered or anticipated in meeting the objective or standards

Obstacles that could be encountered in meeting the MN RES are primarily if our energy sales deviate significantly from our forecast, or if the capacity factors of our existing renewable energy resources deviate significantly. If one of these
events were to occur, the timing of acquiring additional renewable resources would likely change depending on the magnitude of the deviation.

Cost is also potentially an obstacle to achieving MN RES compliance in the future. If the Production Tax Credit (PTC) is terminated or substantially changed, the uncertainty of future tax credits could serve to push the cost of wind energy much higher. This would make additional procurement of wind more costly than current wind purchases that have the full PTC value in place.

(4) Potential solutions to the obstacles
As stated above, we have not experienced obstacles to achieving compliance with the MN RES other than cost. Cost reductions associated with better supply-chain management in the wind industry and technological improvements may alleviate cost concerns in the future.

10.2 Minnesota RES Rate Impact

§216B.1691 Subd. 2e – Rate Impact of Standard Compliance
GRE assesses the RES rate impact using two calculation methodologies:

1. The Commission approved MN RES rate impact methodology, and
2. A market assessment comparing the annual cost of our existing renewable energy contract costs with MISO market prices.

10.2.1 PUC Approved RES Rate Impact Methodology

On Nov. 6, 2013, the Commission issued a Notice of Comment Period on Cost Impact Reports under Docket No. E999/CI-11-852. The Commission made a final determination on Oct. 2, 2014, on the methodology required to develop the MN
RES rate impact, and subsequently filed its Order on Jan. 6, 2015. We have used this methodology to create the MN RES Rate Impact Report and determined a levelized benefit of $1.67/MWh ($0.17/kWh) for MN historical RES compliance, and a levelized benefit of $0.48/MWh ($0.05/kWh) for MN future RES compliance. This is presented in Appendix J.

10.2.2 RES Market Assessment

In any particular year, the price we pay for existing renewable energy is likely to be different than actual MISO market prices. We are experiencing higher rates as a result of acquiring renewable energy resources in the past to meet the MN RES. Comparing our existing contract prices with current MISO market prices results in our members paying an additional $43.7 million in 2016 for MN RES wind energy above market prices.

GRE wishes to note that mandates like the MN RES may force us to make non-economic decisions that negatively impact our members’ rates. Mandates like the MN RES require that we secure resources that may not be needed to meet our load requirements, and that may not be cost competitive with other resource options.

10.3 Greenhouse Gas Emissions Reductions

216B.2422 Subd. 2c. Long-range emission reduction planning.
Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals.
established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.

Minnesota Statutes 216H.02 Subdivision 1 states:

It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.

GRE’s current resource portfolio has resulted in a 21 percent reduction in our 2015 contribution to statewide carbon dioxide emissions compared with 2005 levels, well meeting the 2015 reduction goal. Our calculation methodology for this value is provided in Appendix H. Figure 41 depicts GRE’s historic contribution to statewide greenhouse gas emissions and compares them to the Act’s reduction goals.
Future greenhouse gas reductions are difficult to predict since our expansion plan modeling does not allow market sales, and limits market purchases. These are variables that significantly impact greenhouse gas emissions reductions under the Minnesota Next Generation Energy Act. Our expansion plan model also does not accurately reflect the impact of flexible operations at Coal Creek Station on reduced emissions.

While our contribution to statewide greenhouse gas emissions has decreased by 21 percent from 2005 levels, Great River Energy’s total CO₂ emissions across our generation fleet have decreased by 27 percent. Our overall CO₂ intensity has decreased by almost 22 percent. Our historic mass emissions and intensities are depicted in Figures 42 and 43, respectively.
Figure 42 - GRE CO2 Emission Trend

![Graph showing CO2 emission trend from 2005 to 2015 with a reduction from 2005 of 1.7% to 27.3%]

Figure 43 - GRE CO2 Intensity Trend

![Graph showing CO2 intensity trend from 2005 to 2015 with a reduction from 2005 of 1.3% to 21.9%]
10.3.1 Costs, opportunities and technical barriers

There are some challenges that GRE faces in continuing to reduce carbon emissions below 2005 levels even with our exit from our G3 obligations and the retirement of Stanton Station. Coal Creek Station is still a large and cost-effective generator for our members. If the plant were to continue to operate as it has historically, it would be difficult for the plant to assist in meeting the goals outlined in the Minnesota Next Generation Energy Act. While we have taken innovative and responsive steps to operate the plant more flexibly to better respond to market prices, the operational impacts and resulting emissions reductions have yet to be quantified. It is likely that the increased flexibility of the station will result in more frequent ramping and more time spent at minimum load as more wind comes into the region. This is expected to reduce the plant’s carbon emissions, however the extent of the reduction is difficult to quantify. Nevertheless, it is in our members’ best interest to continue to operate Coal Creek Station, as it provides reliable and cost-effective generation to our members and the region.

Further emission reductions will also occur starting in 2017 with the retirement of Stanton Station and the co-firing of natural gas at Spiritwood Station. We will continue to pursue carbon reductions in our generation portfolio to the extent practicable, and will continue efforts to meet the carbon reduction goals outlined in the Minnesota Next Generation Energy Act.

Our expansion plan modeling does not reflect meeting Minnesota’s Next Generation Energy Act greenhouse gas emission reductions goal being met in 2025, we believe, however, this is because of the limitations of the model, as described above. Our initiatives to help reach the 2025 goal include continued conservation and energy efficiency, the retirement of Stanton Station, the
addition of 400 MWs of wind in the early 2020s, flexible operations at Coal Creek Station, co-firing Spiritwood Station with natural gas, and additional market purchases.

### 10.4 Environmental Externalities

Minn. Stat. § 216B.2422 subd. 3 states:

(a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.

(b) The commission shall establish interim environmental cost values associated with each method of electricity generation by March 1, 1994. These values expire on the date the commission establishes environmental cost values under paragraph (a).

GRE used the most recently approved environmental externality values as updated in the Commission’s June 16, 2016, Order in Docket E-999/CI-00-1636 for our capacity expansion modeling in this IRP.

The midpoint value of the externality costs was used to create the Reference Case and identify the cost addition of imputing externality values into our
planning process. Several other cases throughout the modeling process included externality values. The high and low ranges of the approved values were also included in a run based off the expected values for evaluation. For a full summary of the runs including externality values, see Section 9 on modeling methodology.

Docket E-999 /CI-07-1199 established a future cost of regulation of CO₂. The Aug. 5, 2016, Commission Order established 2016-2017 values for resource plans at a range of $9-$34 / ton CO₂ beginning in 2022. In our resource plan, the Commission approved future cost of carbon regulation values in 2017 dollars were substituted for the CO₂ externality value in runs including externalities beginning in the year 2022 and beyond. Additionally, the high and low ranges of the future cost of carbon regulation were included in runs based off the base case of high and low externalities. For a full summary of the runs including future cost of carbon regulation values, see Section 9 on modeling methodology.

### 10.5 Supply Side Energy Savings

**Commission Order Point 4(a) in Docket ET2/RP-14-813 stated:**

“Provide detailed documentation of its strategies for achieving supply-side energy efficiency savings, the savings these strategies have achieved, and GRE’s overall progress toward meeting the goal of saving 1.5 percent of its statewide energy sales to member cooperatives.”
GRE intends to evaluate and potentially implement a variety of supply-side improvements in its generation fleet over the planning period. The following projects have been identified as potential efficiency improvements at one or more of our generation facilities. Those projects that have specific implementation timelines are indicated below.

- **HVDC Converter Station Upgrades (2018-2019)**
- **Compressed air system upgrades**
- **Dust collection ductwork upgrade**
- **Clean-up air classifier**
- **Air heater efficiency enhancements**
- **Fan Variable Frequency Drives (2019-2020)**
- **Boiler superheat temperature improvements (2021)**
- **Plant lighting upgrades, including LED lighting**
- **Scalping wheel upgrade**
- **Mill Motor IRIS PD Continuous Monitoring**
- **Mill Motor Quick Disconnect (2016)**
- **Turbine Sensitized Packing**
- **Coal Creek Station Flexible Operations (2016)**

In addition, we will evaluate projects to reduce losses in the transmission and distribution systems, such as transformer upgrades, feeder upgrades and system modifications that improve system losses. As projects are implemented and system benefits quantified, they will be included in future reporting. The supply side projects that we have executed currently represent a 0.5 percent energy savings as reflected in our most recently filed CIP Approval Letters by the DOC, attached as Appendix E.
The specific measure lifetimes that are used will vary depending on particular project. In most instances the lifetime of the measure will be assumed to be 15 to 20 years.

10.6 Customer Composition of Member Cooperatives

Commission Order Point 4(b) in Docket ET2/RP-14-813 stated:

“Discuss the customer composition of its individual member distribution cooperatives and the unique opportunities for conservation that certain customers may provide.”

Appendix K shows the composition of individual member energy sales by class. Our members are primarily residential. Section 6 discusses our energy efficiency achievements and programs that our members have and are implementing toward energy efficiency. Section 6 also discusses the limitations and opportunities that are present in evaluating conservation programs with disproportionately residential service territories.

10.7 Use of Capacity Expansion Model

Commission Order point 5(a) in Docket ET2/RP-14-813 stated:

“Continue to use an appropriate capacity expansion model.”
GRE continues to use System Optimizer (SO) as the capacity expansion modeling software for resource planning purposes. The vendor of SO has stopped updating the model, and is actively transitioning to a new software platform. The vendor has indicated that support will not be discontinued, however updates will no longer be provided.

GRE is currently evaluating other capacity expansion models for potential use in future planning.

10.8 Evaluation of Retirement, Rate Impacts, and Discussion of Retirement Process

Commission Order point 5(c) in Docket ET2/RP-14-813 stated:

“Continue to evaluate cost-effective retirement of its coal plants, and include in its coal plant retirement analysis the rate impact of various retirement dates, as well as a discussion of any decommissioning and site remediation costs.”

10.8.1 Stanton Station

In 2016, our board of directors determined that Stanton Station is no longer economic to continue operation in the market at current and expected energy market price levels. Stanton Station is planned to retire on May, 1 2017. Accordingly, we developed and have begun to execute plans to decommission Stanton Station.
10.8.2 Coal Creek Station

We have no plans to retire Coal Creek Station. We believe the station will continue to produce reliable, affordable power for our members well into the future.

Coal Creek Station’s possible retirement was evaluated, as required by the Commission’s order in our last IRP. The evaluation was conducted by allowing the model to select Coal Creek Station retirement within the economic optimization of the portfolio and also explicitly forcing Coal Creek Station to retire. When the model was allowed to economically select retirement of the station, it did not retire it under normal and expected conditions. This means it is more cost-effective to continue to operate the plant than to retire it. We then conducted sensitivities in the model where we forced the model to retire the station in four different years: 2020, 2024, 2028 and 2030. Results of this modeling show higher costs than when the station does not retire. The net present value of the revenue requirements (PVRR) is highest, or most costly, when the plant is forced to retire in 2020.

We estimated the potential decommissioning costs that might be associated with the retirement of Coal Creek Station and included this in the modeling. These costs are only a high level, generic estimate. A more refined cost estimate would take into consideration station and site specifics, resale of some equipment, scrap metal prices and other factors. However, as we do not plan to retire the station, we have not conducted this kind of cost estimate.

Similarly, the site-remediation costs are specific to the geographic location of the unit facing retirement and have the potential to vary drastically based on the level to which we decide to remediate the site. These are costs and
decisions that are made in real-time after a decision to retire a generator is made, and therefore have not been discussed or theorized for Coal Creek Station.

10.8.3 Spiritwood Station

Continued operation of Spiritwood Station is in the best interest of our members and we have no plans to retire the plant. Spiritwood Station is included in our Preferred Plan for the following reasons:

- Spiritwood Station is a new plant that went into commercial operation in 2014;
- Spiritwood Station is more efficient as a CHP facility than a conventional coal plant at 60 to 65 percent efficiency;
- Spiritwood Station provides a hedge for energy market prices and natural gas prices;
- GRE has long-term commitments beyond the planning period to supply process steam to two commercial customers, and may enter into a third arrangement to supply process steam in the near term;
- Spiritwood Station has a positive impact on the local economy through 51 operating jobs. This includes 32 direct jobs at the plant, and 19 indirect jobs for transporting DryFine lignite from Underwood to Spiritwood.

We conducted initial model testing runs to determine if the capacity expansion model was an appropriate means of evaluating Spiritwood Station’s operations. We found that the model does not consider the complex characteristics of a CHP operation, like Spiritwood Station. Since the model does not consider the comprehensive nature of the plant, the model results and its characterization
of Spiritwood Station cannot be relied upon to make a determination on the future of the asset.

Most conventional coal-based power plants are 30 to 35 percent efficient. As a CHP plant, Spiritwood Station is more efficient because it takes advantage of the energy in the steam. In a conventional power plant, that steam is typically released to cooling towers. Since the steam from Spiritwood Station is used as process steam for the adjacent facilities, the plant is 60 to 65 percent efficient. More efficient plants emit less CO₂. Spiritwood Station, as a much more efficient plant, emits much less CO₂ per MWh than most other coal-fired power plants.

The value that Spiritwood Station provides to commercial customers as a steam host is not accounted for, nor are GRE’s contractual commitments to provide steam to the commercial customers on a long term basis. Furthermore, the model does not reflect binding commitments to commercial customers or the full economic value of the plant’s role as a steam host. Due to these limitations, we did not conduct further retirement analysis in the model and do not include test run results in this plan.

10.9 Hydroelectric Resource Cost Assumptions

Commission Order point 5(d) in Docket ET2/RP-14-813 stated:

“Use a broader range of cost assumptions for potential hydroelectric resources.”

The proposed new hydro power included in our 2014 IRP filing was modeled as an estimate of what a final hydro power purchase agreement might look like in
2020. In our current planning process, we are no longer considering a new hydro power supply agreement.

Our experience is that large hydroelectric power pricing and energy profiles are highly dependent upon market prices, and are ultimately dependent upon an executed agreement. Absent better information, we model hydro the same as market energy prices, since the two supplies can be interchangeable. We believe our modeling of a broad range of market energy prices in this resource plan is a reasonable substitute for modeling the potential cost of a hydro resource.

10.10 Scenarios Excluding Sales into Wholesale Market

Order Point 5(e) in Docket ET2/RP-14-813 stated:

“Evaluate scenarios in which GRE’s capacity expansion model excludes consideration of energy sales to the wholesale market.”

GRE has not submitted any runs as part of this resource planning process where energy sales to the market are allowed. In our modeling we allowed for market energy purchases in our expected case of up to 20 percent.
10.11 1.5 Percent Energy Savings

Order Point 5(f) in Docket ET2/RP-14-813 stated:

“Continue striving to save energy equal to 1.5 percent of its annual energy sales to member cooperatives.”

GRE continues efforts to achieve energy savings of 1.5 percent of annual sales to members. Our April 7, 2015, CIP results and plan is included as Appendix E, and indicates that our 2015 CIP plan collectively meets the statutory energy savings goal of 1.5 percent of gross annual retail sales excluding sales to any CIP-exempt customers.