GREAT RIVER ENERGY®
A Touchstone Energy® Cooperative

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October 31, 2014

PUBLIC DOCUMENT
TRADE SECRET AND PRIVILEGED DATA EXCISED

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of Great River Energy's 2014 Resource Plan
Docket No. ET2/RP-14-813

Dear Dr. Haar:

Great River Energy ("GRE") is a not-for-profit generation and transmission cooperative which provides wholesale electric service to 28 distribution cooperatives in Minnesota and northwestern Wisconsin. We respectfully submit this 2014 Resource Plan to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. §216B.2422 and Minn. Rules Chapter 7843.

This filing is made in compliance with the Commission's Order in our previous Resource Plan proceeding, Docket No. ET2/RP 12–1114. This Resource Plan covers the forecast period of 2015 to 2029, and identifies how we propose to reliably meet our member-owner cooperatives' energy needs in a cost-effective and environmentally responsible way. We are submitting a balanced plan that provides options and flexibility over the next 15 years.

Based on GRE's strategies and modeling, we have developed a Preferred Plan that reliably meets our members' needs at least cost in an environmentally responsible way, while complying with all requirements. Our Preferred Plan adds new wind and hydro energy to our power supply portfolio; continues our energy efficiency and conservation programs; and proposes to terminate a long-term obligation to purchase power from a coal-fired generating plant in Wisconsin. We will continue to own and operate our existing power plants, which are among the most reliable and efficient in the country.

Appendices B, G and I of this Resource Plan contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data, following Minn. Stat. §13.37 and Minn. Rule 7829.0500. A statement providing the justification for designating and excising the Trade Secret Data follows this letter.

As reflected in the attached Affidavit of Service, this Resource Plan has been filed electronically via e-dockets. Courtesy copies of the non-public version of this Resource Plan are being delivered to the Commission and the Department of Commerce. The public version of this Resource Plan has been served on those parties on the service list. The public version of the filing will be posted on GRE's website at www.greatriverenergy.com.

Please contact me at (763) 445-6103 or lrossmccalib@grenergy.com if you have any questions regarding this filing.

Sincerely,

Laureen Ross McCalib

Laureen L. Ross McCalib
Manager, Resource Planning and Regulatory Affairs
Great River Energy

c: Service List

Docket No. ET2/RP-14-813

Statement of Great River Energy Regarding Designation and Excision of Trade Secret Information

Pursuant to the Minnesota Public Utility Commission's Revised Procedures for Handling Trade Secret and Privileged Data, which implement the intent of Minn. Stat. §13.37 and Minn. Rule 7829.0500, Great River Energy ("GRE") has designated parts of Appendices B, G and I of our 2014 Resource Plan as Trade Secret.

GRE has designated as Trade Secret, and excised, certain information from the public document version of the Resource Plan to prevent disclosure of information regarding the formulas, compilations, methods, techniques and processes that GRE employs in identifying, obtaining, managing and comparing various resources. This information is highly confidential, is the subject of reasonable efforts by GRE to maintain its secrecy, and derives independent economic value, actual or potential, from not being generally known to or accessible by the public, our competitors and suppliers, who might otherwise gain a commercial advantage over GRE if the information was made public. If the information were to be publicly available, it would jeopardize the ability of GRE and our members to provide reliable energy at affordable rates.

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Dr. David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

In the Matter of Great River Energy's 2014 Resource Plan	Docket No. ET2/RP-14-813 **Initial Filing**

CERTIFICATE OF SERVICE

I, Donna Boe, hereby certify that I have this day served a copy of the following, or a summary thereof, on Dr. Burl W. Haar and Sharon Ferguson by e-filing and First Class mail, and to all other persons on the attached service list by electronic service or by First Class mail.

Great River Energy
2014 Resource Plan

Dated this **31st** day of **October, 2014**

/s/ DONNA BOE
Donna Boe
Executive Assistant
Great River Energy
12300 Elm Creek Blvd
Maple Grove, MN 55369-4718
(763) 445-6100

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Docket No. ET2/RP-14-813

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Great River Energy
Resource Plan
2015-2029
Docket No. ET2/RP-14-813

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Submitted to the Minnesota Public Utilities Commission

October 31, 2014

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PREAMBLE

Great River Energy's (GRE) Integrated Resource Plan (IRP) is our proposal to reliably meet our member-owner cooperatives' (members) energy needs in a cost-effective and environmentally responsible way. We are submitting a balanced plan that provides options and flexibility over the next 15 years.

GRE is a not-for-profit cooperative which provides wholesale electric service to 28 distribution cooperatives in Minnesota. Our members serve approximately 655,000 accounts, or about 1.7 million people.

GRE is well positioned to meet our members' future energy needs as we continue to adapt to a changing industry and economy. Our Preferred Plan includes additional wind and hydro energy; continuing our energy efficiency and conservation programs; and the termination of a long-term obligation to purchase power from a coal-fired generating plant in Wisconsin. We will continue to own and operate our existing power plants, which are among the most reliable and efficient in the country. Our Preferred Plan shows a 28 percent reduction in the carbon dioxide intensity of our system by 2029 from 2012 levels, using EPA's draft compliance formula in its proposed Clean Power Plan.

Our generation portfolio includes facilities of various fuel types, and has been crafted over decades for reliability, affordability and environmental performance. Our new combined heat and power plant comes on-line this fall. Spiritwood Station will be twice as efficient as a typical coal-fired power plant. Our patented DryFining™ system improves the quality of the lignite coal we use at two of our facilities, resulting in better plant efficiency and lower emissions.

We have taken action to prepare for likely greenhouse gas regulations, including implementing cost-effective projects to reduce CO_2. We have developed a 250 kW solar project at our Maple Grove office. Additional solar projects are under development in our member communities.

GRE and our members have long offered programs that encourage conservation and energy efficiency improvements. We are currently evaluating special programs for plug-in electric vehicles and are assessing the role we can play to promote their use.

During the preparation of this IRP, we worked with our members and a variety of other interested parties to discuss our planning efforts. We continue to seek clarity through engagement and have invited external stakeholders to discuss our business and the challenges we face.

Our resource plan meets Minnesota's planning criteria in evaluating resource plans. The plan complies with all legislative and regulatory requirements, including the state's renewable energy standard. This plan responds to the Minnesota Public Utilities Commission's order in our 2012 IRP filing.

We invite the Commission to review and accept our resource plan filing and to support our members' conclusion that this plan is in their best interest and is in the best interest of their end-use members.

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1. NON TECHNICAL SUMMARY

Great River Energy's (GRE) Integrated Resource Plan (IRP) is our proposal to reliably and safely meet our member-owner cooperatives' (members) energy needs in a cost-effective and environmentally responsible way. We propose a balanced plan that provides options and flexibility over the next 15 years.

As is demonstrated by the plan, GRE is well positioned to meet our members' future energy needs as we continue to adapt to a changing industry and economy. Our preferred expansion plan (Preferred Plan) includes additional wind and hydro energy; continues our energy efficiency and conservation programs; and looks to terminate a long-term contract for power from a coal-fired plant in Wisconsin. Under our Preferred Plan, we will continue to own and operate our existing power plants, which are among the most reliable and efficient in the country.

Following the Minnesota Public Utilities Commission's (Commission) decision in our 2012 Integrated Resource Plan, Docket No. ET-2/RP-12-1114, we have further refined our resource planning strategy, made changes to our planning process, reviewed other Minnesota utility IRP filings and decisions, and engaged in expanded outreach with external stakeholders and other interested parties. What we learned during these processes has informed the development of our Preferred Plan.

We have evaluated the impact on us of the United States Environmental Protection Agency's (EPA) proposed Clean Power Plan regulating CO_2 emissions from existing power plants on our system and our Preferred Plan. We have analyzed the proposed regulations and determined that we can continue to operate all of our fossil-fuel fired units and still comply with the Clean Power Plan rules, as the rules are drafted today. Our Preferred Plan shows a 28 percent reduction in carbon dioxide intensity of our system by 2029.[1]

[1] Carbon dioxide emission intensity calculations are completed in accordance with the compliance calculation methodology proposed by the U.S. Environmental Protection Agency's Clean Power Plan, 79 *Federal Register* 34830, June 18, 2014.

Our Preferred Plan is consistent with our corporate mission statement. It meets our triple bottom line of cost, reliability and the environment. It also meets the five factors to consider in Integrated Resource Plans as set forth in the Minnesota Rules.[2]

1.1 GRE and Our Member-Owner Cooperatives

GRE is a not-for-profit electric generation and transmission cooperative serving the wholesale power needs of 28 members. Through our members, we supply electric energy to nearly 655,000 customers in Minnesota and a portion of western Wisconsin. These customers include residences, farms, commercial and industrial facilities and other customers representing approximately 1.7 million people. We provide service to our members through long-term power supply and transmission service agreements. Our members' service territories are shown in Figure 1-1.

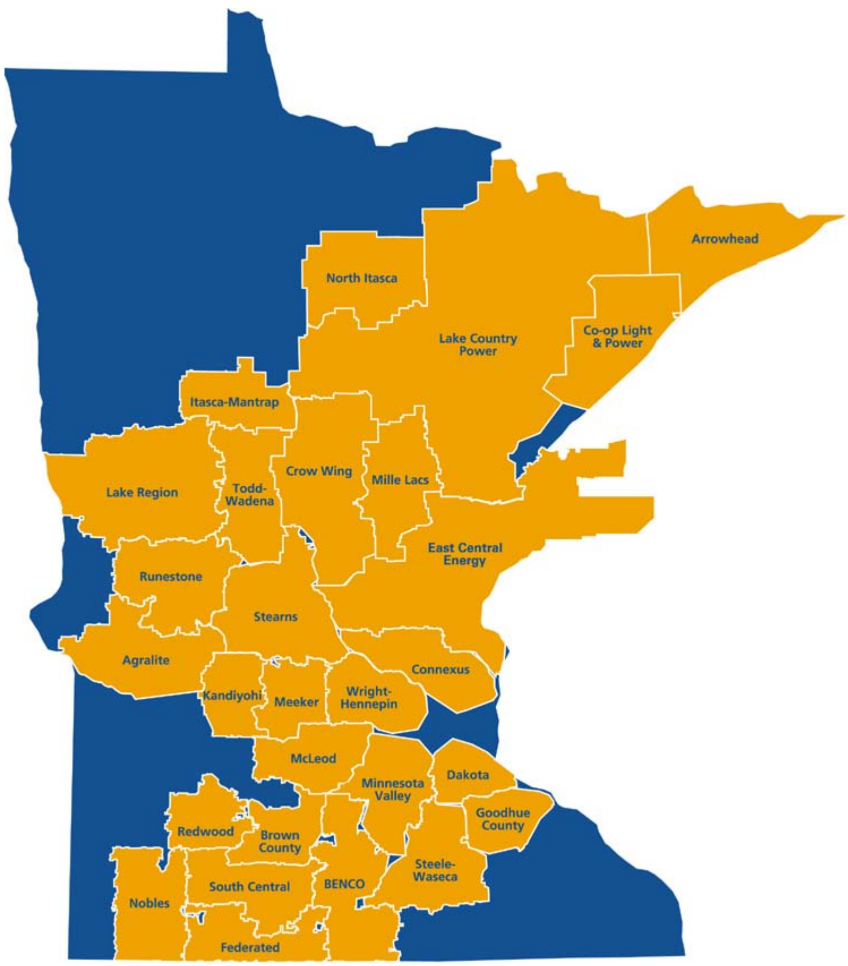

Figure 1-1. GRE members service territories.

[2] Minn. Rules part 7843.0500, subpart 3.

As a cooperative, our members, who are also our customers, own GRE. Cooperatives provide services to their members on a not-for-profit basis and are intended to allow their members to satisfy their common needs more effectively than if each member acted independently.

Cooperatives have developed guidelines by which they put their values into practice. These are national guidelines that are used by all cooperatives, not just electric cooperatives. The cooperative principles are considered in governance decisions and in interactions with the community.

The seven cooperative principles are:

1. **Voluntary and open membership**: Cooperatives are voluntary organizations open to all persons able to use their services and willing to accept the responsibilities of membership without gender, social, racial, political or religious discrimination.
2. **Democratic member control**: Cooperatives are democratically controlled by their members, who participate in setting policies and making decisions by casting one vote each on various matters at annual meetings.
3. **Members' economic participation**: Members contribute equitably to the capital of their cooperative. Although part of that capital is generally the common property of the cooperative, members may receive limited compensation. Members allocate surpluses for any of the following purposes: development of the cooperative; benefitting members in proportion to their transactions with the cooperative; and supporting other activities approved by the membership.
4. **Autonomy and independence**: If cooperatives enter into agreements with other organizations, including governments, or raise capital from external sources, they do so based on terms that ensure democratic control by their members and maintain their cooperative autonomy.
5. **Education, training and information**: In order to receive effective contributions from members, elected representatives, managers and employees, cooperatives provide education and training on current energy issues. They also inform the general public about the nature and benefits of the cooperative model.
6. **Cooperation among cooperatives**: Cooperatives serve their members most effectively and strengthen the cooperative movement by working together through local, national, regional and international structures.
7. **Concern for community**: While focusing on member needs, cooperatives work for the sustainable development of their communities through policies accepted by their members.

Cooperatives from a variety of industries adhere to these principles, which keep them firmly rooted in the communities they serve while also ensuring that they are held accountable by their consumers.

Electric cooperatives are private, independent, and not-for-profit electric utilities. They are owned by those they serve. They are established to provide at-cost electric service and 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 was formed in 1999 when two Minnesota generation and transmission cooperatives, founded in the 1950's, combined their operations.

GRE provides power supply services to two types of members: All Requirements (AR) members and Fixed Obligation (Fixed) members. With limited exceptions, the 20 AR members purchase all of their power and energy requirements from us. The eight Fixed members purchase a fixed portion of their power and energy requirements from us. All supplemental requirements for the Fixed members are provided by an alternate power supplier.

Table 1-1 provides a list of GRE's members and their office locations.

Table 1-1. GRE members and office locations.

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

Governance

As a cooperative, GRE has a democratic governance structure. We are governed by a board of directors that includes 24 directors elected by our members from our members' boards of directors. Our members are governed by their own boards of directors that are elected from their member-consumers.

GRE's members elect GRE's board and approve all significant new generation resources. GRE's board sets wholesale power rates, budgets, policies, and strategies. We have cost based rates that are established by a member-approved rate formula.

Our members provide direction and oversight for GRE at many levels. Our members are engaged with us through regular meetings with our member CEOs, regional meetings and member staff working groups.

GRE's Vision, Mission and Triple Bottom Line

GRE's vision is to keep cooperative energy competitive. Our mission is to provide our members with reliable energy at affordable rates in harmony with a sustainable environment. We refer to our mission statement as our "triple bottom line." Our board of directors uses this vision and mission in making resource decisions and other organizational decisions.

Consistent with our vision and mission, GRE has been working to refine our resource planning strategy to address the current complex and uncertain environment in the electric utility industry. This work has led to certain decisions that will provide us with future flexibility in responding to greenhouse gas regulations. These decisions are incorporated in and influence this IRP; including:

- Accelerate depreciation of Coal Creek Station and Stanton Station beginning in July 2013;
- Meet load growth with conservation, energy efficiency, renewable energy, natural gas and market purchases; and
- Develop and demonstrate solar, distributed and other non-traditional projects.

1.2 The Preferred Plan

Our Preferred Plan includes continuing our energy efficiency and conservation programs; adding wind and hydro energy; and terminating a long-term obligation to purchase power from Dairyland Power Cooperative Genoa Unit 3 (Genoa 3), a coal-fired plant in Wisconsin. Under our Preferred Plan, we will continue to operate the coal-fired power plants that we own.

GRE owns three coal-fired power plants, all of which are located in North Dakota: Coal Creek Station (1,163 MW), Stanton Station (187 MW) and Spiritwood Station (99 MW). Our modeling and other analysis described in this IRP led us to the conclusion that these baseload power plants are least cost resources that should be retained during the 15-year forecast period of this IRP. Several factors lead to this conclusion:

- GRE's coal plants are our only significant baseload resources. Eliminating any of these plants would create unacceptable exposure to the market nearly every day of the year.

- GRE has over $1 billion invested in our coal plants. Much of the investment is in connection with environmental upgrades. Although we have started to accelerate the remaining depreciation of Coal Creek Station and Stanton Station in 2013 so that they will be fully depreciated by 2028, any retirement of either of these plants before that time would require GRE to write off significant assets.
- GRE's coal plants are efficient, least cost resources. All of our financial analysis indicates that our coal plants provide the economic foundation for the affordable rates enjoyed by our members and the physical foundation for the reliability of GRE's service to our members.
- GRE's coal plants are fully compliant with all applicable environmental regulations.
- Our analysis indicates that, under the EPA's proposed Clean Power Plan, GRE will be able to continue to operate all of our coal plants. Over the planning period under the proposed EPA methodology, we expect to achieve a 28 percent reduction in carbon dioxide intensity from 2012 levels.
- Our modeling resulted in no retirements of our owned coal plants, under expected market and load growth conditions.

While a majority of our generation comes from coal, we have taken important steps to diversify our energy fuel types. Between 2001 and 2009, we added more than 1,200 megawatts (MW) of natural gas generation in the form of peaking plants. We added 469 MWs of purchased wind power between 2005 and 2010. We also obtain renewable energy through hydroelectric energy purchases from the Western Area Power Administration and seasonal exchange agreements with Manitoba Hydro.

We generated approximately 11 percent of our electricity from renewable energy in 2013, including generation that uses refuse derived fuel from our Elk River Energy Recovery Station and power purchases from eight wind farms in Minnesota, North Dakota and Iowa. Hydroelectric power provided 13 percent of our electricity production in 2013. Coal-based energy provided 67 percent of our electricity production in 2013, down from 80 percent in 2005.

Our Preferred Plan continues the fuel diversity trend described above, and actively moves us toward increasing reliance on fossil-free energy. Our Preferred Plan:

- Meets load growth with conservation, energy efficiency, renewable energy, natural gas and the market;
- Is a least cost plan, keeping rates lower than other plans;
- Meets all regulatory and legislative requirements;
- Continues to provide optionality as the industry evolves;
- Is based on our vision and mission;
- Best meets our members' needs;
- Is an outcome of modeling which included many sensitivities;
- Reduces our carbon dioxide intensity by 28 percent from 2012 under the proposed EPA Clean Power Plan; and
- Reduces our coal energy production as a portion of our total energy in 2029.

Under the Preferred Plan, the timing of the generation additions and subtractions is shown in Table 1-2.

Table 1-2. GRE's Preferred Plan resource additions and subtractions.

	Additions					Subtractions				
	New Central Solar	New Wind	New SCCT	New CCCT	New Hydro	Genoa 3	Spirit-wood	Stanton	Coal Creek Unit 1	Coal Creek Unit 2
2015	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	(119)	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	200	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
2026	-	100	-	-	-	-	-	-	-	-
2027	-	100	-	-	-	-	-	-	-	-
2028	-	200	-	-	-	-	-	-	-	-
2029	-	200	-	-	-	-	-	-	-	-

Our projected load and capability under the Preferred Plan is shown in Figure 1-2 below.

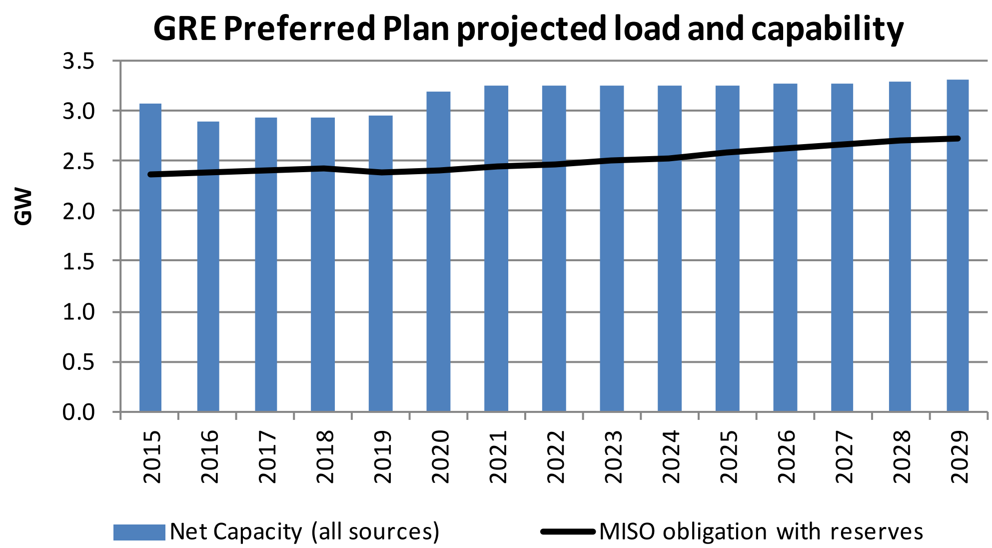

Figure 1-2. Preferred Plan load and capability position.

Our projected energy by fuel type under the Preferred Plan is shown in Figure 1-3 below.

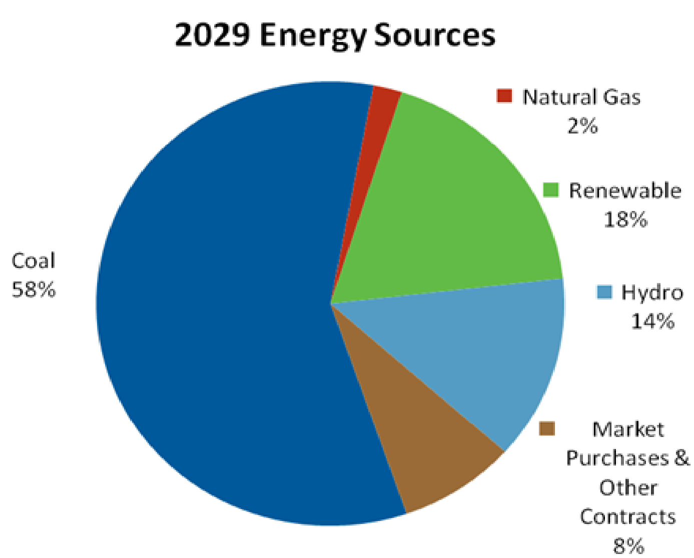

Figure 1-3. Preferred Plan projected energy position in 2029.

The Preferred Plan allows for options in resource decision making as environmental regulations solidify. The plan is robust by minimizing the risks of unexpected changes in energy and demand, market prices and market interaction.

The Preferred Plan considers load growth, energy efficiency, costs of existing and new generation resources, federal and state environmental policy, and regulatory and legislative requirements. This Preferred Plan provides our members with reliable capacity and energy over the forecast period, utilizing energy efficiency and conservation in cost-effective ways, utilizing our existing assets, moving to lower coal dependence, and managing costs.

The Commission's Criteria for Review of Resource Plans

Minnesota Rule 7843.0500, subpart 3 describes the criteria the Commission uses to review resource plans. These criteria are:

A. Maintain or improve the adequacy and reliability of utility service;
B. Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. Minimize adverse socioeconomic effects and adverse effects upon the environment;
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.

Our IRP, including the Preferred Plan, meets the above set of criteria as detailed in Section 2.

1.3 Strategies and Initiatives

GRE has engaged in and will continue to engage in a number of innovative initiatives to address our members' needs and the evolving energy industry. A summary of initiatives that we are engaged in is listed below. These initiatives provide us with flexibility, help us to understand changes in the industry, and prepare us for a less carbon intense future. Additional information on each of the initiatives below can be found in Section 3.

External Stakeholder Outreach and Engagement

GRE invited external stakeholders from the environmental community, business and the public sector to a facilitated discussion process to discuss our business and the challenges we are facing. We sought to understand their views on pressing issues, and to hear their perspective on our organization and business. Through this process, we gained valuable insight into the priorities of our stakeholders. Our resource planning process was informed by these external stakeholder discussions.

DryFining™ Technology

GRE developed the innovative DryFining™ fuel enhancement process whereby lignite coal is dried using residual (or waste) heat from a power plant and mechanically refined to separate out a portion of the naturally occurring sulfur and mercury in the raw coal. The dried and refined coal has multiple benefits, including increased efficiency and lower greenhouse gas emissions. We have installed DryFining™ at Coal Creek Station, reducing that plant's CO_2 emissions by 4 percent.

Accelerated Depreciation of Coal Creek Station and Stanton Station

GRE has determined that it is in the best interests of GRE and its members to reduce GRE's exposure to greenhouse gas regulations in a measured and responsible manner that minimizes rate impacts and ensures reliable service. To best achieve this goal, we believe it is important to build flexibility into the resource planning process. As a result, we began accelerating depreciation of Coal Creek Station and Stanton Station in 2013. GRE plans to fully depreciate these coal-based resources by 2028 to create greater optionality in the future. We believe this action will provide more options for these plants in the future.

Solar Photovoltaic Project Research and Demonstration Project

GRE is working to better understand the capabilities of solar energy. GRE developed a solar photovoltaic (PV) array at our Maple Grove headquarters with a capacity of 254 kilowatts (kW) which adds to the original 72 kW array installed on our building roof in 2008. The objective of the new solar project is to help GRE and our members become more familiar with solar technologies, specifically to learn how solar performs and what it takes to plan, finance and execute solar projects.

Member Site Distributed Solar PV Demonstration Projects

GRE is working with our members to identify potential sites for GRE to install 20 kW solar facilities in their communities. Site identification, material procurement and design have been occurring and will continue in the coming months for as many as 18 installations. Construction began in the summer of 2014 with all facilities expected to be in service by late 2015.

Member Community Solar Initiatives

GRE members Lake Region Electric Cooperative and Connexus Energy have recently announced community solar offerings to their members. The Connexus Energy community solar project, at 245 kW and 792 panels, is believed to be the largest community solar project in Minnesota. The panels are available for members to purchase and in return receive a kilowatt hour credit on their electricity bills for 20 years. GRE member Wright-Hennepin Cooperative Electric Association was the first Minnesota electric utility to offer its members a community solar option, and they have now completed a second phase of solar development.

DOE SunShot Initiative Solar Utility Network Deployment Acceleration (SUNDA)
The U.S. Department of Energy (DOE) and the National Rural Electric Cooperative Association (NRECA) signed a cooperative agreement for a multi-state 23 MW solar installation research project that seeks to identify and address barriers to PV deployment at cooperatives. GRE is one of 15 participating cooperatives supporting the initiative.

DOE SunShot Innovative Solar Business Model (ISBM) Project
In support of the U.S. Department of Energy SunShot Initiative's goal to enable large-scale deployment of solar energy technologies without subsidies, Rocky Mountain Institute (RMI) received funding to test innovative solar business models that benefit utilities, customers and solar providers. GRE members Dakota Electric Association and Steele-Waseca Cooperative Electric are participating in the RMI study.

Electric Power Research Institute (EPRI) Integrated Grid Initiative
EPRI is on a fast track to develop a benefit/cost framework for distributed energy resources (DER) integration, establish interconnection guidelines and establish best practices for incorporating DER into grid planning and operations. GRE financially supports this initiative and has staff dedicated to utilize the findings in its planning and operations and those of its members.

Spiritwood Station
Spiritwood Station is the first utility-scale combined heat and power plant (CHP) in North Dakota designed to serve more than a single third-party steam user. Spiritwood Station will produce electricity and industrial process steam for the Midcontinent Independent System Operator, Inc. (MISO) market and will produce industrial process steam for sale to third parties located nearby. The station will be in full commercial operation on November 1, 2014. This CHP facility will help make progress toward President Barack Obama's August 2012 executive order calling for 40 gigawatts (GW) of new CHP by 2020.

Southern Minnesota Energy Cooperative

Southern Minnesota Energy Cooperative was formed by 12 electric distribution cooperatives for the proposed purchase of electric service territory in southern Minnesota from Alliant Energy. Five of the 12 distribution cooperatives are AR members of GRE. The impact to GRE will be an additional load by our members of approximately 27 MWs in 2025. This additional load has been factored into our forecast in this IRP.

Smart Meter Initiative: Meter Data Management System

As part of the Department of Energy's Smart Grid Demonstration Project (SGDP), GRE, Lake Region Electric Cooperative, and Minnesota Valley Electric Cooperative have come together to procure a secure information-sharing system. The new Meter Data Management System will allow the cooperatives to cooperate, collaborate, and coordinate meter data through the new system.

Electric Vehicle Program

GRE and our members are in the process of developing an electric vehicle (EV) program, which will embrace and encourage EV technology for our members. The program will help us and our member owners become leaders in the utility EV market by collaborating, educating, marketing and providing enhanced infrastructure access.

New Diversity Exchange Agreement between GRE and Manitoba Hydro

GRE and Manitoba Hydro Electric Board (MHEB) executed a new 200 MW Diversity Exchange Agreement in July 2013 that will begin on November 1, 2014 and continue through April 30, 2030. The agreement allows GRE to acquire summer capacity from MHEB and MHEB to acquire winter capacity from GRE. The agreement also provides GRE the opportunity to acquire hydroelectric energy from MHEB.

Potential Hydro Energy post 2020

GRE and MHEB signed a Memorandum of Understanding (MOU) to jointly investigate the sale of up to 600 MWs of electricity from MHEB to GRE, commencing in approximately 2020.

New Bilateral Contracts Executed

GRE has entered into six new bilateral contracts of various quantities and durations since we filed our 2012 IRP. These contracts help to optimize our portfolio by selling surplus capacity, lowering our rates, and providing benefits to the counterparties with whom they are transacted.

Planning Process

Our planning process has evolved to gain input from external stakeholders and to allow our model to select retirements of our coal units if it is economic to do so.

1.4 Environmental Compliance

GRE is in full compliance with all applicable environmental regulations and is preparing to meet all expected future regulations. We are closely monitoring the EPA's proposed Clean Power Plan.

We have taken substantial steps to mitigate the impact of our operations on the environment. It is integral to our planning efforts and embedded in strategic imperatives to balance affordable rates, reliability and environmental stewardship. Our efforts to enhance our environmental stewardship include adding renewable resources to our portfolio, operating our facilities in accordance with registered environmental management systems, investing in emissions controls, and developing commercial uses for our facilities' byproducts. Our efforts include concrete capital projects that are consistent with the U.S. President's Climate Action Plan.

Carbon Dioxide Emissions Reductions

GRE has taken significant steps to reduce our carbon intensity and overall CO_2 emissions since 2005. Our current resource portfolio has already resulted in a 19 percent reduction in our contribution to statewide carbon dioxide emissions[3] between 2005 and 2013 from our owned and purchased generation resources.

Minnesota Next Generation Act of 2007

In this Act, Minnesota set a goal of reducing greenhouse gas emissions from 2005 levels by 15 percent, 30 percent, and 80 percent by the years 2015, 2025 and 2050, respectively. As measured under this Act, our current resource portfolio has already resulted in 19 percent reduction in carbon emissions from our 2005 carbon emissions levels. In 2015, we expect to sustain or exceed a 15 percent reduction in carbon dioxide emissions on our system compared with 2005 emission levels. We believe our carbon dioxide emissions reductions will continue along this trend, and will result in a 26 percent reduction in 2029 from 2005 levels using our Preferred Plan.

[3] GRE's contribution to statewide carbon dioxide emissions are calculated in accordance with methodologies recommended by the Department of Commerce in the Southern Minnesota Municipal Power Agency *Integrated Resource Plan* Docket No. ET9/RP-13-1104. The methodology is described further in Section 4.

EPA and Green House Gas draft rules

On June 2, 2014, the EPA released proposed guidelines for carbon dioxide (CO_2) emissions from existing power plants. The proposed Clean Power Plan would establish a nationwide goal to reduce CO_2 emissions by 30 percent from 2005 levels. To accomplish that goal, the EPA has proposed emissions intensity reduction targets that are unique to each state.

GRE does not have any affected units in Minnesota that are included in the EPA draft rules. Therefore GRE's Minnesota-only carbon dioxide intensity under the Clean Power Plan is zero. Our Preferred Plan would also have a Minnesota-only carbon dioxide intensity under the Clean Power Plan of zero.

GRE has been evaluating how the EPA draft rules could affect our generation and our members. An illustrative way to assess the rule's impact to GRE is to evaluate GRE without any regard to state boundaries, that is, as if GRE were a state. If we ignore state boundaries and follow EPA's proposed compliance determination formula, our Preferred Plan results in a carbon dioxide intensity reduction of 28 percent below 2012 levels in 2029 on our system.

More information about our environmental initiatives can be found in Section 4.

1.5 Conservation and Energy Efficiency

GRE has long worked with our members to offer programs that encourage their end-use members to manage electricity costs through conservation and energy efficiency improvements. Helping members use energy wisely not only reduces their costs, but also contributes toward more efficient, affordable and reliable electric service. We coordinate a portfolio of programs with our members to encourage homeowners and businesses to replace outdated, inefficient equipment with newer, efficient installations. Programs encourage members to pursue efficient alternatives ranging from small upgrades, such as compact fluorescent light bulbs and LED holiday lights, to large installations, such as ground-source heat pumps, variable frequency drives and manufacturing process improvements.

We have estimated total energy efficiency reductions over the forecast period to be 1.5 percent of total retail energy savings in each year of this IRP. We intend to accomplish this by continuing to drive energy savings equivalent of 1.0 percent through member side activities, while obtaining energy efficiency savings equivalent of 0.5 percent from investments in supply side efficiency throughout our and our members' systems. More information about our conservation and energy efficiency initiatives can be found in Section 5.

1.6 Distributed Energy Resources

GRE and our members continue to evaluate the technical and cost impacts of on-site Distributed Energy Resource (DER) systems. We expect our members may introduce or utilize DER systems over the forecast period, particularly solar energy.

GRE is investigating the benefits and costs of distributed energy resources through several initiatives, including the Electric Power Research Institute Integrated Grid Initiative, the DOE SunShot Initiative Solar Business Model, the DOE SunShot Initiative Solar Utility Network Deployment Acceleration, Research and Demonstration and Member Demonstration Projects and participation in Minnesota's Combined Heat and Power stakeholder process. More information about our DER initiatives can be found in Section 6.

1.7 The Planning Process

GRE's long term resource planning is an iterative process that takes input from our strategies, expansion plan modeling, industry changes, environmental policy, and regulatory and legislative requirements, our members, and external stakeholders. We have committed to meeting our load growth with conservation and energy efficiency, renewable energy, natural gas and the market.

GRE's approach to resource planning is to develop a plan that is robust in meeting and balancing our objectives of cost effectiveness for our members, maintaining reliable service, and attention to environmental stewardship, while meeting all state and federal regulations. GRE's board of directors determines the overall strategy for our organization and develops direction on greenhouse gas emissions regulations, energy fuel types, and changes in our power supply portfolio.

An enhancement to our planning process over the past two years has been to engage external stakeholders and interested parties in our strategies and our planning process.

GRE developed this resource plan using the following planning process:

- Engage interested stakeholders;
- Determine modeling assumptions and requirements;
- Evaluate conservation and energy efficiency potentials;
- Estimate distributed energy resource impacts;

- Develop econometric energy and load forecasts to determine growth for our AR members;
- Develop system energy and demand requirements using the AR member forecasts and add Fixed member requirements, transformation and transmission losses and DC line losses;
- Develop our load and capability position;
- Identify regulatory and legislative requirements, including externalities and regulatory costs;
- Allow our existing coal plants to be retired in the modeling process if economic to do so;
- Model cases that include multiple sensitivities to identify potential expansion plans;
- 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.

Since our 2012 IRP filing, we have changed the way our modeling is conducted so that the model now evaluates generation alternatives, or coal plant retirements, as an option for selection if it is economic to do so. More information about our planning process can be found in Section 7.

1.8 Forecast

In determining energy and demand forecasts over the 15 year forecast period, GRE developed strictly econometric forecasts based on weather, residential consumers, employment, member rate, propane and population. No after-the-fact adjustments were made by our members or by us to the econometric forecasts.

GRE's annual energy requirement is forecast to increase from 13,041,357 MWh in 2015 to 15,591,718 MWh in 2029, reflecting a compounded annual growth rate (CAGR) of 1.3 percent. GRE's first five-year CAGR is forecast to be 0.5 percent. The 1.3 percent CAGR is lower than the growth experienced during early to late 2000's. GRE believes this is attributed to the slow recovery in the residential consumer class, and customer and utility sponsored efforts in conservation and efficiency.

GRE's annual coincident peak demand requirement is forecast to increase from 2,452 MWs in 2015 to 2,825 MWs in 2029, reflecting a CAGR of 1.0 percent. GRE's first five-year coincident peak demand requirement CAGR is 0.15 percent. The 1.0 percent CAGR is lower than the growth experienced during early to late 2000's.

In conducting our modeling, we included sensitivities on the energy and demand forecasts of high and low load growth, varying levels of conservation and energy efficiency, distributed generation, and electric vehicles.

This resource plan was developed using a planning requirement that is based on MISO's coincident peak. More information about our forecast methodology and results, MISO Module E Resource Adequacy Obligation and Demand Response can be found in Section 8.

1.9 Expansion Plan Analysis and Results

GRE uses a Ventyx software product called System Optimizer™ to conduct expansion plan modeling. The model evaluates future resources needed to meet demand by finding an optimal expansion plan. The model solves for the least cost expansion plan for a given set of input assumptions while meeting all load and reserve margin requirements.

GRE evaluated 32 separate cases with individual and combined sensitivities as a way to assess outcomes for different future scenarios. The assumptions and sensitivities used in the modeling were environmental externality costs, carbon regulatory costs, energy and demand growth, new resource costs, market prices, market interactions, coal prices, natural gas prices, planning reserve margins, MISO diversity factor, Renewable Portfolio Standards, energy efficiency & conservation, customer owned distributed generation, electric vehicles, and coal generation retirement and coal contract termination.

Expansion plans were identified by combining the cases that resulted in similar resource additions and/or retirements over the 15 year forecast period. Based on the 32 cases considered, 12 different expansion plans were identified. We then evaluated the expansion plans on the Minnesota Rules' resource plan Factors to Consider of reliability, cost, environmental impact and risk. Based on these factors, we selected an expansion plan that is our Preferred Plan. More information about our expansion plan analysis and results can be found in Section 9.

1.10 Five Year Action Plan

Consistent with GRE's member needs and strategies, we will pursue the following actions over the next five years:

- Continue implementing conservation and energy efficiency programs while striving to meet or exceed the 1.5 percent per year Minnesota goal;
- Continue to accelerate depreciation on our two largest coal fired stations so that by 2028, the facilities will be fully depreciated;
- Continue to evaluate solar technologies and research the impacts to our member systems;
- Assist our members in developing solar generation in their service territories;
- Remain engaged in potential environmental regulation developments that may have impact on GRE;
- Identify a cost effective arrangement with Manitoba Hydro that will result in adding a zero carbon resource to GRE's portfolio;
- Work with Dairyland Power Cooperative (DPC) to terminate our long-term contractual obligation to purchase 50 percent of the capacity and energy from Genoa 3;
- Continue to work toward efficiency improvements at our generation facilities;
- Comply with the EPA's Clean Power Plan rules when they are issued;
- Develop an electric vehicle program to encourage the use of electric vehicles; and
- Engage external stakeholders in our business and our planning.

We believe these actions will continue to prepare us for changes in the energy industry and evolving energy and regulatory policy.

1.11 Legislative and Regulatory Compliance

GRE is in compliance with the legislative and regulatory requirements related to Integrated Resource planning in the state of Minnesota. We are meeting Minnesota's Renewable Energy Standard (RES). We have adequate renewable energy and renewable energy credits (RECs) to meet the 25 percent requirement in 2025. Based on expected load growth, we will need additional renewable energy in the late 2020's to comply with the RES. Our Preferred Plan includes the addition of 600 MWs of wind beginning in the year 2026 to meet this requirement.

We have submitted a report on the RES rate impact in this filing, using two calculation methodologies: a forward looking planning analysis and an annual cost comparison of renewable energy costs compared to MISO market prices. In the forward looking analysis, the increase in the net present value of the revenue requirements as a result of the RES is 2.2 percent. Comparing current renewable energy resources to MISO market prices, we found that if our members were able to purchase replacement market energy instead of energy provided from our renewable energy sources, they would have seen a reduction in cost of $32 million in 2013. This is because MISO market prices were below the cost of our renewable energy resources in 2013. The Commission made a final determination on October 2, 2014 on the methodology required to develop the RES rate impact. The timing of this decision did not allow us to include the Commission's approved methodology in this Integrated Resource Plan. We will adopt the Commission's approved methodology for calculating the RES rate impact in our next resource plan.

We have included the Commission approved externalities and regulatory costs in our modeling. We have identified a reference case, a regulatory case and our Preferred Plan.

We have complied with the Commission's 2012 Order in this IRP, and are complying with all other Minnesota statutory and regulatory requirements, as shown in Appendix A: Legislative and Regulatory Compliance Requirements.

1.12 System Background

GRE has been, and is expected to remain, a summer peaking utility. Our 2014 summer GRE coincident peak was 2,458 MWs. Our 2013 annual sales to members were 12,105,295 megawatt hours (MWh).

GRE owns and operates a resource mix that includes 12 power plants and purchases power from several wind farms and other generating facilities, resulting in more than 3,500 MWs of generation capability. Our power supply portfolio consists of a diverse mix of baseload and peaking power plants, including resources that utilize coal, natural gas, fuel oil, wind, hydro, refuse-derived fuel (RDF), landfill and biogas energy.

Our baseload resources supply the majority of our required energy and capacity. We own our baseload resources with the exception of Genoa 3.

Our peaking resources, which are primarily combustion turbines, provide a significant and necessary portion of our capacity. They supply a relatively small amount of our energy. Our wind resources which are primarily contracted resources, providing energy, but a relatively small amount of capacity.

We are a MISO transmission owning member and market participant and are subject to MISO's tariff and other requirements. We use MISO's required Planning Reserve Margin in our planning process. We plan to a MISO coincident peak, as required in MISO's Module E. We have evaluated our system's coincidence with MISO's peak and have found an average of a 10 percent diversity factor over the past eight years. We have also modeled our resource needs based on our own system peak as an alternative.

GRE has added renewable resources ahead of the timing requirements of the Minnesota RES. We currently have 468 MWs of wind resources under contract. We process municipal waste into RDF and use the RDF to generate 31 MWs at our Elk River Energy Recovery Station (ERERS) facility. We purchase energy from a three megawatt landfill gas generator in Elk River and from two dairy farms with anaerobic digester projects. We installed a 200 kW wind generator and a 72 kW solar photovoltaic system at our headquarters building in Maple Grove at the time the building was built.

In 2014, GRE installed 250 kW of solar generation at our headquarters, and by 2015 our members will have installed 380 kW of solar generation in their service territories. In addition, our members purchase energy from a number of distributed generation projects connected to their distribution systems, including landfill gas, small wind and photovoltaic generators.

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 more than 4,500 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 1-3.

Table 1-3. GRE transmission lines and substations.

Voltage	Mileage
69 kV or less	3,042
115 kV	468
161 kV	46
230	523
345	75
500	70
Total AC transmission	4,224
400 kV DC	436
Total transmission line	4,660
Total transmission substations	102

Because of intertwined service territories, many of our member systems' loads are interconnected to transmission facilities owned by other utilities and vice versa. For the most part, GRE and the interconnected utilities have turned over functional control of their respective transmission systems to 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 a reasonable rate for our members.

New transmission projects may come before the Commission for review and approval during the forecast period.

2. THE PREFERRED PLAN

GRE is well positioned to meet our members' future energy needs as we continue to adapt to a changing industry and economy. Our preferred plan includes additional wind and hydro energy; continuing our energy efficiency and conservation programs; and the removal of a long-term obligation for power from a coal-fired generating plant in Wisconsin. We will continue to operate our existing power plants, which are among the most reliable and efficient in the country.

Our generation portfolio includes facilities and contracts of various fuel types, and has been crafted over decades for reliability, affordability and environmental performance. Our new combined heat and power plant comes on-line this fall.

During the preparation of this IRP, we worked with our members and a variety of other interested parties to discuss our planning efforts. We continue to seek clarity through engagement and have invited external stakeholders to discuss our business and the challenges we face.

Our preferred resource plan meets state criteria and complies with all legislative and regulatory requirements, including the state renewable energy standard. The Preferred Plan balances the Factors to Consider outlined in Minnesota's rules in evaluating resource plans. We believe this plan is in our members' best interest and that of their end use members.

2.1 Description of the Preferred Plan

GRE's Preferred Plan continues conservation and energy efficiency efforts, adds non-fossil hydro energy and wind, and terminates the Genoa 3 purchase obligation from our portfolio. The Preferred Plan meets GRE's mission and vision, and complies with all state and federal regulatory and legislative requirements.

We expect to add 200 MWs of hydro energy in 2020, 600 MWs of wind beginning in 2026, and terminate our obligation to purchase capacity and energy from the Genoa 3 facility in 2016. In this Preferred Plan, we retain existing generation facilities and work with our members to add distributed solar generation. This plan is in the best interest of our members, and meets their requirements of cost, reliability and environmental stewardship.

Table 2-1 below reflects the resource changes and timing that are included in the Preferred Plan.

Table 2-1. Preferred Plan MW additions and subtractions.

	Additions					Subtractions				
	New Central Solar	New Wind	New SCCT	New CCCT	New Hydro	Genoa 3	Spirit-wood	Stanton	Coal Creek Unit 1	Coal Creek Unit 2
2015	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	(119)	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	200	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
2026	-	100	-	-	-	-	-	-	-	-
2027	-	100	-	-	-	-	-	-	-	-
2028	-	200	-	-	-	-	-	-	-	-
2029	-	200	-	-	-	-	-	-	-	-

2.2 Load and Capability and Energy under the Preferred Plan

The Preferred Plan results in adequate capacity and energy to serve our members over the forecast period. Figure 2-1 below reflects our capability position under the Preferred Plan, along with our load and MISO reserve requirements.

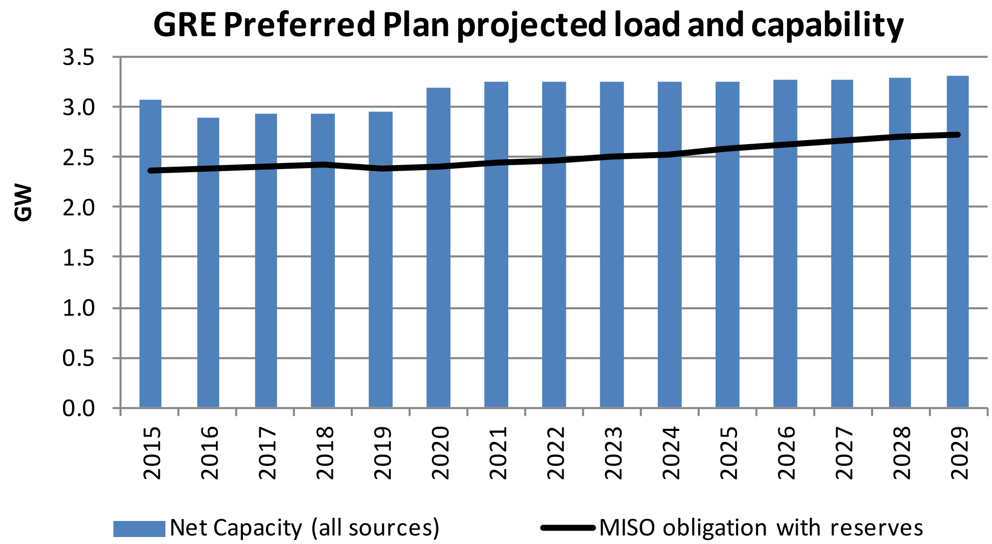

Figure 2-1. Load and capability position under the Preferred Plan.

With the addition of hydro, solar and wind, along with the removal of Genoa 3 from our portfolio, our energy position in 2029 will reflect a lower production of coal energy compared to today. Figure 2-2 below reflects our expected energy by fuel type with the Preferred Plan in the year 2029.

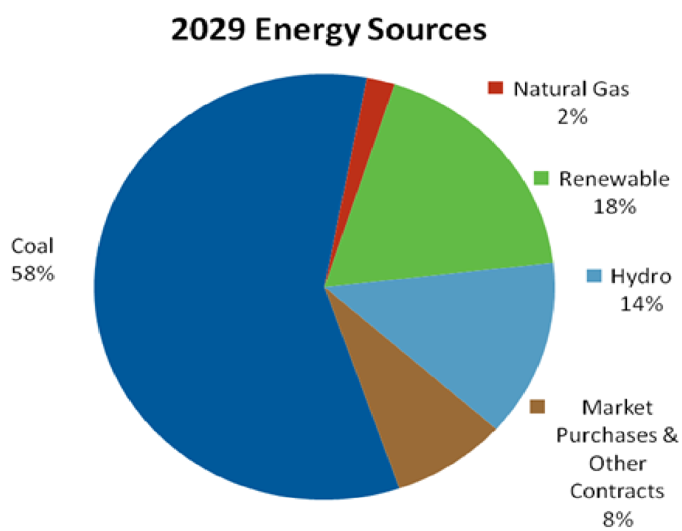

Figure 2-2. Energy by fuel type with the Preferred Plan in 2029.

The Preferred Plan meets our members' needs in balancing our triple bottom line of cost, reliability and environmental impact. This plan continues the utilization of low cost energy keeping our members rates low. The plan maintains adequate resources to meet

MISO's resource adequacy requirements. The plan continues to reduce coal energy as a percent of our total energy generation. The Preferred Plan results in a 28 percent reduction in carbon dioxide intensity in 2029 compared to 2012, using the EPA's methodology in their proposed Clean Power Plan. The plan allows for options in resource decision making as environmental regulations solidify. The plan is robust by minimizing risk of unexpected changes in energy and demand, market prices and market interaction.

2.3 Meeting the Minnesota Rules IRP Review Criteria

GRE is committed to providing our members with reliable energy at competitive rates and to do so in harmony with a sustainable environment. This resource plan is consistent with that commitment. The plan takes into consideration the factors set forth in Minn. Rules part 7843.0500, subpart 3.

As tested against the factors set forth in Part 7843.0500, subpart 3, GRE's Preferred Plan meets the objectives of:

A. Maintain or improve the adequacy and reliability of utility service;

1. GRE's Preferred Plan provides adequate capacity and energy to meet our members' requirements over the forecast period.
2. GRE's Preferred Plan provides adequate capacity to comply with MISO's Module E requirements, including MISO's Planning Reserve Margin, over the forecast period.
3. GRE's Preferred Plan does not rely on the MISO capacity market to meet our needs over the forecast period. It does not unduly rely on the MISO energy market.
4. GRE, on its own and through MISO, is subject to the reliability compliance requirements of NERC and the MRO.
5. GRE has ongoing access to market resources in addition to the self-sufficient resources in the Preferred Plan.
6. GRE regularly reviews our near-term capacity situation and makes transactions and adjustments accordingly.
7. GRE is actively engaged with 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.
8. Our generation facilities provide reliability and stability of the energy market and the electric transmission system.

B. Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

1. GRE is committed to implementing conservation and energy efficiency to help our members and their customers make the most of the energy they use and to minimize the need for new supply side resources. GRE, in concert with our members, has met and will strive to continue to meet the Minnesota 1.5 percent Energy Conservation Policy Goal.
2. GRE uses a capacity expansion optimization model that identifies a least cost plan in developing our Preferred Plan.
3. GRE's Preferred Plan results in lower revenue requirements while meeting regulatory requirements than other expansion plans considered.
4. GRE has improved the utilization of our existing assets through efficiency improvements and commercialization of waste heat and other byproducts of generating electricity.
5. GRE actively participates in MISO's energy markets and pursues bilateral transactions to minimize overall costs.
6. GRE's Preferred Plan continues the utilization of our low cost generating facilities through the forecast period.

C. Minimize adverse socioeconomic effects and adverse effects upon the environment;

1. GRE is committed to implementing conservation and energy efficiency to help our members and their customers make the most of the energy they use and to minimize the need for new supply side resources.
2. GRE, in concert with our members, will strive to meet the Minnesota 1.5 percent Energy Conservation Policy Goal.
3. GRE will meet all future load growth with conservation and energy efficiency, renewable energy and hydro, natural gas and the market.
4. GRE is supporting our members in their development of solar energy resources.
5. GRE is meeting Minnesota's Renewable Energy Standards.
6. GRE has reduced our CO_2 emissions by 19 percent in 2013 from 2005 levels.
7. GRE has improved utilization of our existing assets and reduced direct and indirect emissions through efficiency improvements, combined heat and power projects and commercialization of byproducts of generating electricity.
8. GRE is developing 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 our 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. GRE has a diverse resource portfolio that includes DSM and conservation, renewable energy, natural gas, hydro, coal, and bio-fuels of various sizes, locations, technology types and contract terms.
2. GRE has considered a range of sensitivities to identify a plan that is robust in the face of major uncertainties.
3. GRE is accelerating depreciation on its two largest baseload coal plants so that by 2028 the units will be fully depreciated.
4. GRE's largest generation facility has on-site fuel and is not subject to rail delivery challenges.
5. GRE has ongoing access to market resources in addition to the self-sufficient resources in the Preferred Plan.
6. GRE has built and is operating an efficient combined heat and power facility.
7. GRE participates in organizations that have an energy and reliability focus, including EPRI, MISO, FERC, NERC, MRO, MTO, APM, NRECA, Minnesota Rural Electric Association and others to monitor and anticipate developments that may affect us.

3. STRATEGIES AND INITIATIVES

GRE has taken significant action toward our goal of diversifying our portfolio while providing reliable and cost effective power supply. An example of a recent action toward this evolution is the accelerated depreciation of coal-fired Coal Creek Station and Stanton Station over 15 years. We believe this action will provide greater optionality for the future. We have recently added solar generation to our portfolio – at Maple Grove and in our members' service territories, to demonstrate the costs and benefits of new generation sources. We are evaluating opportunities to offer plug-in electric vehicles and plug-in hybrid electric vehicles to our members, and to play a role in increasing infrastructure access by piloting chargers at our headquarters and some members' sites.

The November 2014 startup of GRE's CHP plant, Spiritwood Station, will help make progress toward President Barak Obama's August 2012 executive order calling for 40 GW of new CHP by 2020.

Our IRP process has evolved as well. We considered the Commission's Order from our 2012 IRP and are responding to that Order's individual order points in this IRP. We actively sought input from external stakeholders on our strategies and our resource plan. We changed our modeling process to allow the optimization model to select retirements of coal units if economical.

3.1 Actions and Initiatives

GRE has engaged in and will continue to engage in a number of innovative initiatives to address our members' needs and the evolving energy industry. A summary of initiatives that we are engaged in is listed below. These initiatives provide us with flexibility, help us to understand changes in the industry, and prepare us for a less carbon intense future.

External Stakeholder Outreach and Engagement

In the fall and winter of 2013/2014, GRE invited external stakeholders to a facilitated discussion process to talk about our business and the challenges we are facing. We wanted to understand their views on pressing issues, and to hear what they thought and expected of our organization. By welcoming the perspectives of end-use consumers, financial institutions, low-income advocates and environmental nonprofit organizations, we gained valuable insight into the priorities of those with a vested interest in cooperative electricity in Minnesota. Additional information on this initiative is included in Section 9.

DryFining™ Technology

DryFining™ Technology is a fuel enhancement process developed and patented by GRE that result in increased efficiency of lignite coal. The lignite coal is dried using residual (or waste) heat from the power plant and mechanically refined to separate out a portion of the naturally occurring sulfur and mercury in the raw coal. The dried and refined coal has the following benefits:

- A drier fuel has a higher energy value (Btu per pound), so the power plant handles and burns less fuel.
- The refined fuel produces less emissions of sulfur, mercury, NOx and CO_2.
- The drier fuel has lower transportation costs, because the DryFining™ fuel enhancement process reduces the weight of the water vapor in raw lignite.
- The higher quality fuel is finer and less erosive resulting in lower operating and maintenance costs.

Accelerated Depreciation of Coal Creek Station and Stanton Station

In 2013, the GRE's board of directors determined that it was in the best interests of GRE and our members to reduce the organization's exposure to greenhouse gas regulations in a measured, responsible manner that minimizes rate impacts and ensures reliable service. To create greater optionality in the future, we began accelerating depreciation of Coal Creek Station and Stanton Station in 2013. GRE will depreciate these coal-based resources by 2028, which is significantly sooner than previously planned.

Solar PV Project Research and Demonstration Project

GRE developed a solar PV array at our Maple Grove office that was completed in May 2014. The solar PV array has an electric generation capacity of 250 kW and adds to the original 72 kW array installed on the building roof in 2008. The objective of the new solar project is to help GRE and our members become more familiar with solar technology, specifically to learn how solar performs and what it takes to plan, finance and execute solar projects. The project will measure the performance of different panel technologies, assess the benefits of a variety of inverters, and document lessons learned while designing, permitting and installing the solar array.

Member-sited Distributed Solar PV Demonstration Project

GRE is also working with our members to identify potential sites for 20 kW solar installations in their communities. Site identification, material procurement and design will take place in the coming months on as many as 19 installations. Construction began in the summer of 2014 with all facilities expected to be in service by the fall of 2015.

In addition to these projects, some members are exploring the potential to expand these solar systems with the intent to offer community solar choices for their member consumers.

Member Community Solar Initiatives

GRE is a member of the National Renewables Cooperative Organization (NRCO). Cooperatives across the country formed NRCO to promote and facilitate the development of renewable energy resources for its members. NRCO's main purposes are to facilitate the cost-effective, joint development of renewable resources nationwide for its cooperative-owners, and to help its owners meet the requirements of voluntary and mandatory RES. NRCO has been instrumental in developing community solar projects for its members, providing project development, financing and marketing support.

Working with NRCO, Lake Region Electric Cooperative and Connexus Energy have recently announced community solar offerings to their members. The Connexus Energy community solar project, at 245 kW and 792 panels, is believed to be the biggest community solar project in Minnesota. The panels are available for members to purchase and in return they receive a kilowatt hour credit on their electricity bill for 20 years. The community solar sites are adjacent to the Lake Region Electric Cooperative headquarters in Pelican Rapids, Minnesota and the Connexus Energy headquarters in Ramsey, Minnesota.

Wright-Hennepin Cooperative Electric Association of Rockford, Minnesota was the first Minnesota electric utility to offer its members a Community solar option, and they have now completed a second phase.

DOE SunShot Initiative Solar Utility Network Deployment Acceleration (SUNDA)

The U.S. Department of Energy (DOE) and the National Rural Electric Cooperative Association (NRECA) signed a cooperative agreement for a multi-state 23 MW solar installation research project that seeks to identify and address barriers to PV deployment at cooperatives. The DOE is providing \$3.6 million, matched by a \$1.2 million cost share from NRECA, the National Rural Utility Cooperative Finance Corporation, Federated Rural Electric Insurance Exchange, and PowerSecure International, Inc. GRE is one of 15 participating cooperatives. Although targeted at larger installations, GRE will learn how standardization can help bring down the “soft” costs – labor, procurement, supply chain and other costs – of PV installations and also reduce uncertainty about the effects of these installations on the distribution and transmission system.

DOE SunShot Innovative Solar Business Model (ISBM) Project

In support of the DOE's SunShot Initiative's goal to enable large-scale deployment of solar energy technologies without subsidies, Rocky Mountain Institute (RMI) received funding to test innovative solar business models that benefit utilities, customers and solar providers.

GRE along with members Dakota Electric Association of Farmington, Minnesota, and Steele-Waseca Cooperative Electric of Owatonna, Minnesota, were selected to participate in the RMI study. The project seeks to optimize the value of solar technology while minimizing costs for the benefit of cooperative members. The project is expected to conclude in late 2014, and the findings will be shared with utilities across the country.

Electric Power Research Institute Integrated Grid Initiative

GRE supports EPRI's research, development and demonstration activities, including distributed energy resource integration. Distributed energy resources (DER) that exist today in the U.S. are interconnected to the grid, but are not fully integrated. Integration enables all of the values of DER (e.g., resiliency, voltage support, emissions reductions, and distribution optimization) and allows all electricity users to fully benefit from DER deployment. EPRI is on a fast track (results by end of 2014) to develop a benefit/cost framework, establish interconnection guidelines and establish best practices for incorporating DER into grid planning and operations. GRE financially supports this initiative and has staff dedicated to utilize the findings in its planning and operations and those of its members.

Spiritwood Station

GRE's Spiritwood Station is the first utility-scale CHP plant in North Dakota designed to serve more than a single third-party steam user. Spiritwood Station will produce electricity for the MISO grid and will produce industrial process steam for sale to third parties located nearby. The station will be in full commercial operation on November 1, 2014.

CHP plants such as Spiritwood Station are highly energy efficient because they make more productive use of the low grade thermal energy at the tail end of the steam cycle which, at most plants, is released to cooling towers. After the high pressure steam spins the turbines to generate electricity, Spiritwood Station sends some of this low grade steam to its industrial steam partners, so they do not have to burn their own primary energy in boilers and furnaces to generate their own steam. CHP reduces both capital and operating costs for the industrial steam partners.

Spiritwood Station will be 40 to 66 percent efficient, depending on the amount of steam provided to its steam partners. A third steam partner could help the power plant achieve its maximum design efficiency of 66 percent.

Spiritwood Station's fuel source is lignite coal, which is converted to a higher-efficiency fuel using the innovative DryFining™ fuel enhancement process. In addition to utilizing beneficiated lignite, Spiritwood Station uses Best Available Control Technologies to control emissions.

President Barack Obama signed an executive order on August 30, 2012, to expand the use of CHP, including the deployment of 40 additional gigawatts of capacity in the U.S. by 2020. The use of CHP provides an opportunity to accelerate energy efficiency efforts at industrial facilities.

Dakota Spirit AgEnergy

Midwest AgEnergy Group's Dakota Spirit AgEnergy, a biorefinery, is currently under construction adjacent to Spiritwood Station and is expected to enter commercial operation in early 2015. The biorefinery will utilize steam from the Spiritwood Station plant, eliminating the need for a boiler as part of the biorefinery itself. When it begins operations, the Dakota Spirit AgEnergy biorefinery will produce 65 million gallons of ethanol a year from North Dakota corn, as well as dry and modified distillers grains for livestock, corn oil for biodiesel production and E85.

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 electric service territory in southern Minnesota from Alliant Energy. The 12 cooperatives are BENCO Electric Cooperative, Brown County Rural Electrical Association, Federated Rural Electric, Freeborn-Mower Cooperative Services, Minnesota Valley Electric Cooperative, Nobles Cooperative Electric, People's Energy Cooperative, Redwood Electric Cooperative, Sioux Valley Energy, South Central Electric Association, Steele-Waseca Cooperative Electric, and Tri-County Electric Cooperative. Five of the 12 distribution cooperatives are AR members of GRE. Figure 3-1 below shows a map of the cooperatives and their service territories that are a part of SMEC.

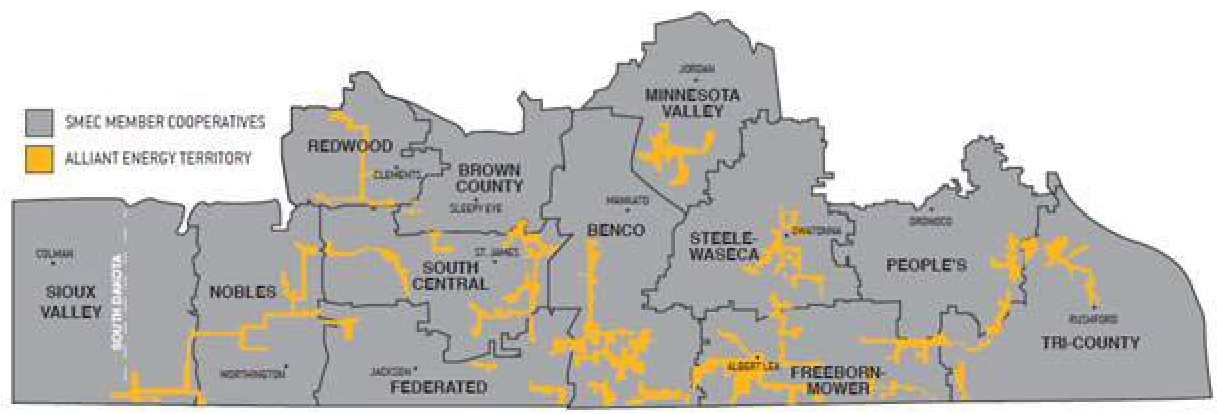

Figure 3-1. Southern Minnesota Energy Cooperative territories.

SMEC reached a definitive agreement to acquire territory from Alliant Energy. The transaction is contingent upon regulatory approval. The acquisition will add approximately 43,000 electric accounts to the systems of all of the 12 SMEC member cooperatives combined. Alliant Energy will continue to serve Minnesota through a 10-year wholesale power agreement with the 12 cooperatives. The agreement is under regulatory review.

The impact to GRE will be an additional load by our members of approximately 27 MWs in 2025.

Smart Meter Initiative: Meter Data Management System

As part of the DOE's Smart Grid Demonstration Project (SGDP), GRE, Lake Region Electric Cooperative, and Minnesota Valley Electric Cooperative have come together to procure a secure information-sharing system that allows the cooperatives to cooperate, collaborate, and coordinate data through a new Meter Data Management System (MDMS).

GRE, Lake Region Electric Cooperative, and Minnesota Valley Electric Cooperative collaborated with National Information Solutions Cooperative (NISC) to create the data system. The meter data management system allows the organizations to take advantage of the large quantities of data generated from the increasing number of data generating sensors deployed on the grid. The MDMS is tasked with verification, validation and analysis of meter data, and interfaces with other systems to make this information widely available.

GRE's multi-tenant meter data management system takes these efficiencies one step further by recognizing the relationship and necessary data transfers between the G&T and Distribution utilities. A multi-tenant MDMS leverages data from systems at both organizations more accurately and efficiently to facilitate data transactions that are necessary for the two entities to conduct their business.

Electric Vehicle Program

GRE and our members believe there are excellent benefits through the use of EV. Increased use of EV is good for our members, the environment, and our future growth by wisely using energy and by reducing transportation greenhouse gas emissions. GRE and our members can play an intrinsic role in getting consumers to consider EV as a personal transportation option. We are in the process of developing a program that will embrace and promote EV technology to our members. The program will help us and our members to evolve as leaders in the utility EV market by collaborating, educating, marketing and providing enhanced infrastructure access.

GRE is currently conducting market research and engaged with EPRI and NRECA Market Research to better understand the perceptions and driving habits of our key audience, the members we serve. We realize that before retail incentives and access strategies are fully developed, it is important for us to better understand our member-consumer perceptions and intentions around adopting and their use of plug-in electric vehicles.

In addition, we are proposing member education and marketing activities including test-drive events, educational campaigns and an increased effort to educate members through traditional media means including web, newsletter and local advertising.

Finally, we are playing a role in increasing infrastructure access by piloting chargers at our headquarters and various cooperative sites, incenting limited public chargers in our members' service territories to test, demonstrate, pilot and learn from the usage and data at selected sites.

New Diversity Exchange Agreement between GRE and Manitoba Hydro

GRE signed a 200 MW seasonal diversity exchange with Manitoba Hydro Electric Board of Winnipeg. The diversity exchange means Manitoba Hydro Electric Board will provide 200 MWs of non-fossil renewable hydroelectric capacity to GRE in the summer to meet our energy needs, while GRE will provide Manitoba Hydro Electric Board with 200 MWs of capacity during the winter. Each utility receives the additional energy during its peak period of the year. The new agreement runs until 2030.

Potential Hydro Energy post 2020

GRE and Manitoba Hydro Electric Board signed a MOU to jointly investigate the sale of up to 600 MWs of electricity from Manitoba Hydro Electric Board to GRE, commencing in approximately 2020. Under the MOU, the utilities have agreed to discuss supplying some of GRE's long-term electricity needs from Manitoba Hydro Electric Board's proposed new hydroelectric stations.

New Bi-lateral Contracts Executed Since the 2012 Filing

GRE has entered into six new bilateral contracts of various sizes and terms since we filed our 2012 IRP. These contracts help to optimize our portfolio by selling surplus capacity and providing benefits to the counterparties with whom they are transacted. These transactions are shown in Appendix B: Generation Resource Characteristics.

Greenhouse Gas Emissions Regulations

Anticipating the likely adoption of greenhouse gas regulations, we have taken action to evolve our portfolio over time to mitigate the risk of potential regulations. We have taken significant steps to reduce our carbon intensity and overall CO_2 emissions since 2005. Among the most significant actions are the development and implementation of DryFining™ at Coal Creek Station and developing a state-of-the-art combined heat and power facility at Spiritwood Station. GRE is committed to adding only low or carbon free resources to our resource portfolio going forward.

Our current resource portfolio has already resulted in 19 percent reduction in carbon dioxide emissions from our 2005 carbon dioxide emissions levels, using the Minnesota Next Generation Act calculation methodology. We expect to sustain or exceed a 15 percent reduction in carbon dioxide emissions on our system compared with 2005 emission levels in 2015.

We anticipate that our Preferred Plan will result in continued reduced carbon dioxide emissions through 2029. As federal greenhouse gas emission regulations solidify over the next several years, we will review our portfolio in light of those regulations.

Minnesota's Next Generation Energy Act of 2007 set a goal 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 (Minn. Stat. § 216H.02, Subd. 1.). GRE has already achieved a 19 percent reduction in CO_2 emissions since 2005. We expect our 2015 CO_2 reductions to be at or greater than 15 percent compared to 2005 levels.

4. ENVIRONMENTAL UPDATE

GRE is in 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 2013, we have achieved the following emission reductions:

- Carbon dioxide (CO_2) emissions have decreased by 19 percent;
- Total sulfur dioxide (SO_2) emissions have decreased by 58 percent; and
- Total nitrogen oxides (NOx) emissions have decreased by 41 percent.

This section discusses significant environmental regulations and requirements that currently apply to GRE's generation resources. All applicable environmental regulations are reflected in GRE's Preferred Plan. Many of these environmental regulations are under review or modification by the EPA. GRE closely monitors EPA's activities with respect to any regulations that may impact our operations.

In addition to our emission reduction efforts, we work 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 emissions controls, and developing commercial uses for our facilities' byproducts. Our accomplishments include capital projects that are consistent with the U.S. President's Climate Action Plan such as the development of DryFining™, a novel multi-pollutant control technology that provides substantive efficiency improvements for the power plants that implement the technology. This technology has been marketed globally.

GRE has actively pursued combined heat and power generation as one of the most efficient means to generate electricity and supply process heat to other industrial processes. The Blue Flint Ethanol plant is co-located with Coal Creek Station where it uses waste steam as its primary source of process energy in lieu of operating its own fossil-fuel fired boiler. Spiritwood Station is a combined heat and power plant with the capacity to generate up to 99 MWs of electricity that will also supply process steam to an existing adjacent malt plant and the Dakota Spirit AgEnergy plant under construction across the road from it. Combined heat and power plants are highly energy efficient because they use the energy in their steam cycle to both produce electricity and satisfy the thermal energy needs of a nearby process plant.

With respect to many existing regulations, we understand their impact on our generating and transmission facilities. We have active ISO 14001 registered environmental management systems at our facilities. These management systems are consistently evaluating compliance with environmental requirements and are periodically audited by third parties to confirm their effectiveness. We are in compliance with current environmental regulations and are making progress to comply with upcoming regulatory deadlines. These applicable environmental regulations include the:

- Acid rain program;
- Mercury and Air Toxics Standards (MATS) rule;
- Regional haze rule;
- Transport rules;
- Aquatic life protection at cooling water intake structures rule (Clean Water Act §316(b)); and
- National Emissions Standards for Hazardous Air Pollutants for major sources: industrial, commercial and institutional boilers and process heaters.

For other emerging regulations we cannot predict, with any certainty, specific final requirements and their exact effect on our resources. Nevertheless, we have included a discussion of the status of the following regulations and their potential impact to our facilities:

- Greenhouse gas emissions;
- National Ambient Air Quality Standards – these standards are both existing and emerging;
- Effluent limitations guidelines;
- Coal combustion residuals management; and
- Phase-out rule for polychlorinated biphenyls in electrical equipment.

4.1 Greenhouse Gas Emissions

There are several greenhouse gas regulations and policies GRE is monitoring and tracking, which will be summarized in this section, including:

- Minnesota Next Generation Energy Act;
- Environmental Protection Agency Existing Source Performance Standards or the Clean Power Plan; and
- Environmental Protection Agency New Source Performance Standards.

Minnesota Next Generation Energy Act

In 2007, the Minnesota legislature enacted the Next Generation Energy Act, which was codified at Minnesota Statutes Chapter 216H. Minn.Stat. 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.*

Our current resource portfolio has already resulted in a 19 percent reduction in our 2013 contribution to statewide carbon dioxide emissions compared with 2005 levels. Under our Preferred Plan we expect to achieve a 15 percent reduction in 2015 and to continue reductions through 2029, reaching a reduction of 26 percent in 2029 from 2005 levels.

Methodology for Calculating GRE's Contribution to Statewide CO_2 Emissions

GRE's historical and forecasted contributions to statewide CO_2 emissions are calculated in accordance with Department of Commerce Division of Energy Resources' (the Department) recommendations contained in the Southern Minnesota Municipal Power Agency's 2014-2028 Integrated Resource Plan for 2014-2028 (Docket No. ET9/RP-13-1104). The Department recommended:

- Start with CO_2 emissions from utility-owned generation;
- Add CO_2 emissions from utility purchases; and
- Subtract CO_2 emissions from sales from utility-owned generation.

Where a bilateral agreement exists for energy purchases and sales that refers to a specific energy source, we utilized the emissions intensity (lb CO_2/MWh) for the specific energy source (e.g., GRE's purchases from DPC's Genoa 3) with the actual amount of energy purchased or sold.

If an energy purchase is not part of a bilateral agreement or the agreement does not specify a specific source for the energy, regional average emission rates are used. The Department recommended using the average CO_2 emission rates for the Midwest Reliability Organization West (MROW) in calendar year 2009, as calculated and summarized in EPA's Emissions & Generation Resource Integrated Database (eGRID). EPA has updated the eGRID database to now include calendar year 2010 data,[4] which we used in our calculations.

If an energy sale is not part of a bilateral agreement, the carbon intensity of GRE's portfolio of energy sources is used to quantify the CO_2 emissions associated with the energy sale.

[4] http://www.epa.gov/cleanenergy/documents/egridzips/eGRID_9th_edition_V1-0_year_2010_Summary_Tables.pdf

The results of the calculations for calculating GRE's contribution to statewide CO_2 emissions are summarized in Table 4-1 for actual emissions in 2005, 2013, and forecasted emissions in 2029 under the Preferred Plan.

Table 4-1. GRE's contribution to statewide CO_2 emissions.

	Actual 2005 tons	Actual 2013 tons	Forecasted 2029 tons
CO_2 from GRE's power plants and Genoa3	14,020,277	12,519,728	10,900,120
CO_2 associated with specific contracted energy purchases	1,279,690	320	-
CO_2 associated with non-specific market purchases	1,176,926	1,078,642	1,017,782
CO_2 associated with specific contracted sales	(498,399)	(265,634)	-
CO_2 associated with sales outside MN	(51,717)	(48,794)	-
CO_2 associated with non-specific market sales	(2,983,620)	(2,221,256)	(2,419,765)
CO_2 associated with retirement of non-energy-related RECs	-	(606,689)	-
GRE's contribution to statewide CO_2 emissions	**12,943,158**	**10,456,316**	**9,498,138**
CO_2 Reduction Relative to 2005		**19.2%**	**26.6%**

Existing Source Performance Standards or the Clean Power Plan[5]

EPA's proposed "Carbon Pollution Emission Guidelines for Existing Sources: Electric Utility Generating Units" was published in the June 18, 2014 *Federal Register* under the authority of Clean Air Act §111(d). The proposed rule is sometimes referred to as Existing Source Performance Standards (ESPS) or the Clean Power Plan (CPP).

EPA states implementation of the rule would lead to a 30 percent reduction in nationwide CO_2 emissions from the U.S. power sector in 2030 compared to 2005 levels. However, EPA uses

[5] GRE has reviewed the proposed rule and participated in numerous meetings and conference calls regarding the proposal, some of which included representatives from EPA. The proposed rule is very complex. EPA has left many questions yet to be answered and has asked significant questions of interested parties. What the final rule will look like is yet to be determined. The narrative information provided herein by Great River Energy is our current best understanding of the proposed rule and EPA's intentions for it.

2012 as the baseline year in setting each state's goal, and if the rule were implemented as proposed, the emissions reduction would be approximately 18 percent in 2030 compared to 2012 levels.

EPA's timeline calls for the rule to be finalized in 2015. If the rule were to be finalized as proposed, states would have to file initial State Implementation Plans (SIP) by June of 2016 and final SIPs as late as June 2018.[6] If a state fails to file an acceptable SIP, EPA would establish a Federal Implementation Plan (FIP) for that state. The schedule for establishing a FIP is not clear. Affected sources would be required to begin reducing emissions in 2020 with full compliance by 2030.

The proposed guideline establishes state-specific CO_2 emission rate goals in pounds of CO_2 emitted per megawatt-hour of electricity produced, which are also called carbon dioxide intensity goals. EPA considered four "building blocks" in setting each state's goal:

- **Building Block 1 Heat rate improvement** – Reducing carbon dioxide intensity of affected generating plants through a 6 percent improvement in coal plant heat rates (i.e., efficiency).
- **Building Block 2 Higher utilization of natural gas combined cycle units** – Reducing emissions from affected generating plants by substituting generation from plants with lower carbon intensity, which EPA calculates by setting the capacity factor of existing natural-gas-fired combined cycle units at 70 percent.
- **Building Block 3 Increased renewables and nuclear generation** – Reducing emissions from affected generating plants by substituting generation from low- or zero-carbon generation (e.g., wind, nuclear).
- **Building Block 4 Increased energy efficiency** – Reducing emissions from affected generating plants resulting from 1.5 percent annual demand-side energy efficiency.

EPA proposes interim goals starting in 2020 with final goals to be met by 2030. The proposal also includes alternate goals with a final compliance date of 2025, on which EPA has requested comments. Table 4-2 summarizes the 2030 goals and their computation for Minnesota.

[6] If a state plan does not involve a multi-state regional approach, the final SIP would be due no later than June 2017. If a state plan involves a multi-state approach, the final SIP would be due no later than June 2018.

Table 4-2. Proposed ESPS 2030 goal computation for Minnesota*.

Minnesota's 2012 baseline Carbon Dioxide Intensity	Coal Rate: 2,318 lb CO_2/MWh Fossil, Renewable & At-risk Nuclear Rate: 1,470 lb CO_2/MWh
Building Block 1 Heat Rate Improvements	6% improvement in the heat rate of all existing coal-fired units, which would result in an average intensity of 2,179 lb CO_2/MWh for Minnesota's coal-fired units
Building Block 2 NGCC Redispatch	Increase dispatch of existing NGCC from a 2012 capacity factor of 24% to a 70% capacity factor in 2020. EPA's model assumes that the increased energy produced by the NGCC plants would replace 11,290,583 MWh/yr that would have otherwise been produced by coal units, or roughly one-half of Minnesota's 2012 coal-based energy generation.
Building Block 3 Renewables	No further renewables used were used to calculate Minnesota's goal. Minnesota already meets the region's 15% renewable goal with 2012 renewables generation at 9,453,871 MWh, which is equivalent to 18% of Minnesota's total generation.
Building Block 3 Under-Construction & At-Risk Nuclear	EPA credits 840,190 MWh of at-risk nuclear generation to Minnesota's goal.
Building Block 4 Cumulative Energy Efficiency	11.72% cumulative energy efficiency reduction resulting in 73,094,474 MWh of avoided in-state energy production. Minnesota's 2012 incremental energy efficiency was 1.08%.
Proposed 2030 Carbon Dioxide Intensity Goal (lb CO_2/MWh)	873 lb CO_2/MWh

* All information and data are taken from EPA's ESPS Docket (http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents) including:

- Spreadsheet "20140602tsd-state-goal-data-computation_1.xlsx/Appendix 1";
- "Goal Computation Technical Support Document," Appendix 5, Docket No. EPA-HQ-OAR-2013-0602, June 2014;
- Technical Support Document "GHG Abatement Measures," Section 4, Docket No. EPA-HQ-OAR-2013-0602, June 2014;
- Spreadsheet "20140602tsd-ghg-abatement-measures-appendix5-4.xlsx"; http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-ghg-abatement-measures-appendix5-4.xlsx

The proposed rule allows states to have flexibility in deciding how much of each building block they choose to use to achieve their requisite goals. States also have the ability to use mechanisms other than the four building blocks to determine how they will comply with the rule. For example, hydropower is not used by EPA to develop the state goals, but EPA is taking comment on allowing states to use hydropower to meet their goals.

Compliance with the state goal would be determined by summing up the total CO_2 emissions from all the affected units within a state, and then dividing it by the MWh of energy generated from all energy sources and the avoided energy demand from energy efficiency. It would look something like the calculation shown in Figure 4-1.

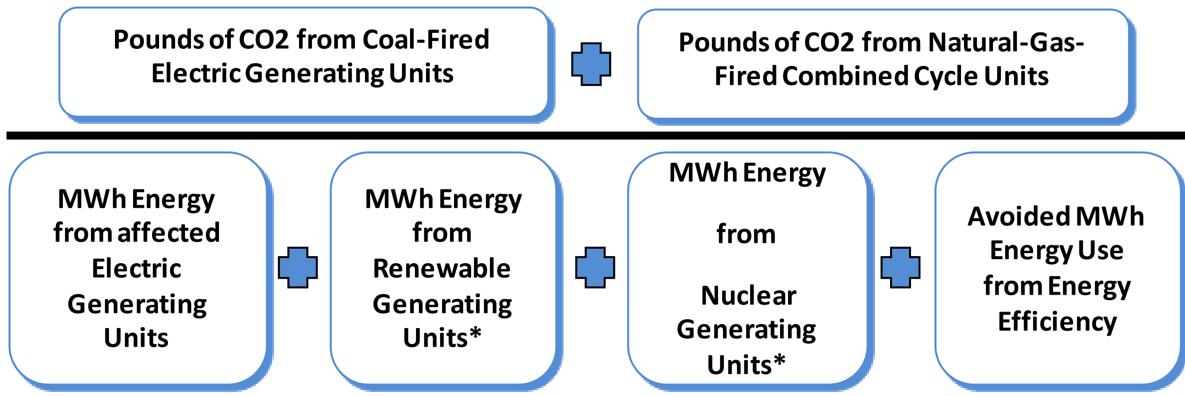

Figure 4-1. Clean Power Plan state compliance calculation.

EPA is taking comment on how biomass emissions and energy and nuclear energy should be accounted for in the final rule.

Clean Power Plan's Impacts to GRE

It is difficult to accurately assess the impacts of the proposed Clean Power Plan to GRE. First, the rule is only a proposal and may change significantly before it becomes a final rule. EPA has laid out numerous specific questions and alternative options on which it is taking comment. Second, the proposed rule does not apply directly to GRE or to any utility. Rather, it applies to the states by prescribing the carbon dioxide intensity goals and laying out the requirements necessary for EPA to approve their plans for implementing the Clean Power Plan. Third, the assumptions used in setting the goals are not necessarily the same assumptions that states must use in determining compliance with the goals. Lastly, it is expected that a final rule, when issued, will be the subject of legal challenges by multiple parties. EPA's authority to regulate power plants under §111(d) is already the subject of a petition filed by Murray Energy Group, which the District of Columbia Circuit court has agreed to hear.[7]

[7] It is extremely rare for the courts to entertain challenges to rules that are not yet final, but Murray reasoned that the proposal could not possibly be legal because the Clean Air Act does not allow regulations to proceed under Section 111(d) if the sector in question is already regulated under Section 112 of the Act. In the case of coal-fired power plants, for example, the Mercury and Air Toxics Standards (MATS) rule does just that; it regulates under §112 the very same facilities the proposed §111(d) rule now attempts to regulate. EPA and other supporters of the proposed rule have argued that the Senate version of the underlying Clean Air Act amendment did not contain the language with the preemptive effect; only the House language did. And both amendments are referenced in the Statutes at Large as codified, creating sufficient confusion to allow the EPA proposal to proceed. However, the plain language of the House amendment remains in the law. And further, Justice Ruth Bader Ginsburg wrote for

The "affected units" EPA proposes to regulate consist of coal-fired steam electric generating units and natural-gas-fired combined cycle (NGCC) plants. GRE does not own or operate any affected units in Minnesota. Accordingly, our Minnesota-only carbon dioxide intensity is zero. Our Preferred Plan would also have a Minnesota-only carbon dioxide intensity under the Clean Power Plan of zero.

Simple cycle combustion turbines are essentially exempt from being affected units if they were built with the purpose of operating at a capacity factor below 30 percent. GRE's natural-gas-fired simple cycle plants were built with the purpose of serving as peaking units with a capacity factor less than 30 percent, and each of our combustion turbines have operated at capacity factors generally less than 10 percent since commencing commercial operations.

Assessment of the Preferred Plan to the Proposed Rule

GRE has been closely following the development and review of the Clean Power Plan proposal in an attempt to evaluate how the proposal could affect our generating plants and our members. However, as we have noted, the rule does not apply directly to GRE and each state's plan for implementing the rule could look substantially different from the EPA's proposed rule. Thus, any analysis is speculative.

Because of the complexity of EPA's individual state approach, we have developed a simplified, illustrative way to assess GRE's Preferred Plan relative to the proposed rule by evaluating GRE without any regard to state boundaries – as if GRE were a state. If we ignore state boundaries and follow EPA's proposed compliance determination formula (Table 4-3), our Preferred Plan results in a 2029 carbon dioxide intensity 28 percent below 2012 levels. Given that the Clean Power Plan goal is to achieve approximately an 18 percent reduction in CO_2 emissions from 2012, GRE's Preferred Plan performs well when analyzed using the EPA's proposed building blocks.

the Supreme Court majority in *AEP v. Connecticut*, 131 S.Ct. 2,527 (2011), referencing ONLY the House language from the statute and noting its preemptive effect. At note 7 of that case, Justice Ginsburg wrote that "EPA may not employ [the 111(d) program] if existing sources of the pollutant in question are regulated under [112]."

Table 4-3. Comparison of GRE's Preferred Plan to EPA's proposed Clean Power Plan.

	2012	2029	Comment
Tons CO_2	**12,440,530**	**10,699,990**	Includes only GRE-owned plants & G3. Excludes market purchases.
MWh	**12,506,764**	**12,394,981**	Includes only GRE-owned plants & G3. Excludes market purchases.
CCS	**9,227,870**	**7,964,160**	Affected unit in proposed CPP.
SS	**1,242,965**	**1,257,523**	Affected unit in proposed CPP.
SWS	**-**	**288,851**	Affected unit in proposed CPP.
G3	**463,573**	**-**	Affected unit in proposed CPP.
Diesel Gen	**-**	**-**	Not affected units in proposed CPP.
Nat Gas CT	**-**	**-**	Not affected units in proposed CPP.
ERS - RDF	**-**	**-**	Not affected unit in proposed CPP.
Wind Purchases	**1,572,356**	**2,883,609**	CPP proposal allows all wind, not just new.
Solar	**-**	**838**	CPP proposal allows all solar, not just new.
New Hydro	**-**	**742,825**	CPP proposal only allows new hydro.
MWh EE	**-**	**1,845,201**	Estimated 2029 EE at 1.5% based on 2029 forecasted demand
CO_2 Intensity ($lb\ CO_2/MWh$)	**1,989**	**1,428**	
% Change		**- 28%**	

EPA New Source Performance Standards for New Units

On January 8, 2014, EPA published a revised proposed rule regulating CO_2 emissions from new fossil fuel-fired electric generating units (EGUs) (primarily coal- and natural gas-fired units) under the Clean Air Act's New Source Performance Standards. The proposed rule establishes separate standards for electric steam generating units (utility boilers and integrated gasification combined cycle (IGCC) units) and for natural gas-fired stationary combustion turbines. The proposed standard of performance for utility boilers and IGCC units is based on partial implementation of carbon capture and storage as the Best System of Emission Reduction (BSER) and sets an emission limit of 1,100 lb CO_2/MWh. The proposed standard of performance for natural gas-fired stationary combustion turbines is based on modern, efficient natural gas combined cycle technology as the BSER and sets a limit of 1,000 lb CO_2/MWh for larger units and 1,100 lb CO_2/MWh for smaller units.

The proposed standards would not apply to existing EGUs, modifications to or reconstructions of existing EGUs, combustion turbines that sell one-third or less of their potential output to the grid, new non-natural gas-fired stationary combustion turbines (i.e., oil-fired), and EGUs for which 10 percent or less of the heat input over a three-year period is derived from a fossil fuel (i.e., an EGU that primarily fires biomass would not be subject to the standards). A source is considered a "new source" for the purposes of the proposed rule if it commences construction after the proposal is published in the *Federal Register*, i.e., after January 8, 2014.

Our Preferred Plan does not contemplate constructing any new fossil fuel-fired EGUs and thus GRE is not impacted by this rule.

4.2 Sulfur Dioxide (SO_2) and Nitrogen Oxides (NOx)

In concert with our triple bottom line, GRE has worked hard to reduce emissions of SO_2 and NOx from our coal-fired power plants. Between 2005 and 2013, we have successfully reduced our power plants' SO_2 emissions by 58 percent and our NOx emissions by 41 percent. Figure 4-2 shows annual emissions of SO_2 and NOx, respectively for years 2005 through 2013.

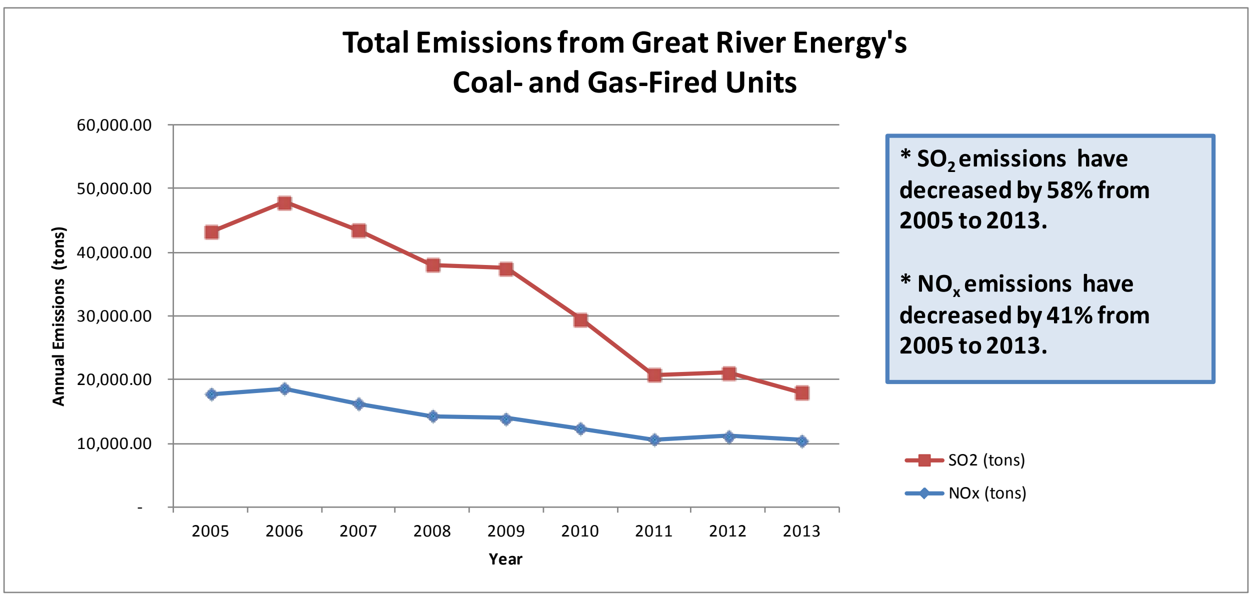

Figure 4-2. Total emissions from GRE's coal- and gas-fired units.

SO_2 and NOx emissions are regulated under the Acid Rain Program, Regional Haze Program, and National Ambient Air Quality Standards.

4.3 Acid Rain Program

The Acid Rain Program under Title IV of the Clean Air Act requires nationwide reductions of SO_2 and NOx emissions by allocating allowances under a cap-and-trade scheme to electric generation facilities for SO_2 emissions based on historic or calculated levels and reducing allowable emission rates for NOx. Coal Creek Station, Stanton Station and Spiritwood Station, as well as several of GRE's combustion turbine stations, are regulated under the Acid Rain Program.

The Acid Rain Program also creates a market for SO_2 emission allowances. Under this regulation, the EPA allots a specified number of SO_2 allowances to each unit for each year. Each unit is required to hold one SO_2 allowance for each ton of SO_2 emissions on a calendar year basis. Excess allowances can be used for compliance by other affected units in a utility's fleet or sold into the marketplace.

GRE's generation units have been performing better than Acid Rain Program requirements for many years. Therefore, GRE has an excess of SO_2 allowances that guarantees compliance by all its affected units with the program requirements with no additional investment. As an example, Coal Creek Station's two units are allotted 44,497 SO_2 allowances per year. Recent upgrades have been made to the scrubbers on both units at Coal Creek Station. Through its use of improved scrubbing and our DryFining™ technology, the station has reduced emissions of pollutants, including SO_2, while improving overall plant efficiency.

Stanton Station's two units are allotted 8,781 SO_2 allowances per year. In 2004, Stanton Station switched from lignite to lower sulfur Powder River Basin coal, resulting in lower SO_2 emissions. Like Coal Creek Station, these extra allowances can be used for compliance by other affected GRE facilities.

The Acid Rain Program regulations limit NOx levels at Coal Creek Station to 0.40 lb/MMBtu at each unit, and at Stanton Station to 0.46 lb/MMBtu for Unit 1 and 0.40 lb/MMBtu for Unit 10. The facilities comply with their applicable limits through the installation of low-NOx burners and other combustion controls including over-fire air. All affected GRE facilities have proper pollution control equipment and operational procedures to ensure compliance with their applicable NOx limits.

4.4 Regional Haze

EPA published final regional haze regulations in 1999. The intent of the Regional Haze rule is to gradually improve visibility in Class I areas, such as national parks and wilderness areas, with a goal of reaching "natural conditions" by 2064. The first phase of this rule requires certain power plants to install Best Available Retrofit Technology (BART) to control SO_2, NOx and particulate matter emissions. In December 2009, the North Dakota Department of Health (NDDH) issued its final BART determinations for public comment as part of its regional haze SIP. This North

Dakota SIP includes requirements for BART-eligible units. For GRE, these are Coal Creek Station (both units) and Stanton Station (Unit 1).

BART emission controls must be installed and operational no later than five years (i.e., April 2017) after EPA approves North Dakota's SIP or finalizes its own FIP. EPA's final SIP/FIP determination for North Dakota was published on April 6, 2012. EPA approved North Dakota's SIP relative to Stanton Station and relative to Coal Creek Station SO_2 and particulate matter emissions. However, EPA rejected part of the North Dakota SIP and issued a FIP for more stringent Coal Creek Station NOx emission controls. GRE disagreed with EPA's FIP and filed a petition for review with the U.S. Court of Appeals for the Eighth Circuit. In 2013 the Eighth Circuit determined that EPA was "arbitrary and capricious" in its determination of a FIP for Coal Creek Station NOx controls. Consequently, the court instructed EPA to either accept the amended North Dakota SIP which provided for technical corrections, or reject it on different grounds before re-issuing a FIP. While EPA has yet to act, it is GRE's expectation that EPA will ultimately approve the North Dakota SIP determination for Coal Creek Station NOx controls.

Coal Creek Station and Stanton Station have been working diligently on BART control strategies and fully expect to meet the regulatory timeline. Coal Creek Station has installed and has been operating DryFining™ as a foundational multi-pollutant control strategy since 2010. In addition, Coal Creek Station has been working on stack modifications in order to comply with the SO_2 limit by the 2017 deadline. Finally, Coal Creek Station engineers recently identified and implemented a cost-effective electrostatic precipitator performance improvement to better control particulate matter, even though BART did not require it.

Stanton Station continues to evaluate dry sorbent injection (DSI) as an acid gas control to comply with its BART SO_2 limit. Currently, Stanton Station has identified that sodium-based sorbents are effective at reducing the SO_2 emissions to meet the BART limit. However, the sodium sorbents do interfere partially with activated carbon's effectiveness at controlling mercury. As such, GRE continues to assess sorbents to better optimize the overall system. The most recent tests were completed in 2013 and involved a micronized lime product, which was injected into expected in late 2014 or 2015 to better understand the balance of plant impacts of the various dry sorbents and their possible interactions with activated carbon for mercury control. For NOx reductions, Stanton Station has recently performed a third-party evaluation of tuning and burner operations to understand Stanton Station's ability to consistently meet the BART NOx limit. Although these tests were encouraging, more work is needed to fully understand continuous operation of a range of operations.

Coal Creek Station's novel multi-pollutant DryFining™ technology is foundational for several regulations including the BART requirements. In addition, Coal Creek Station is spending approximately $25 million on flue gas design updates in order to prepare for the limits. With respect to NOx controls, Coal Creek Station has already spent approximately $6 million on expanded over-fire air and low-NOx burner upgrades on Unit 2. GRE expects to spend an additional $6 million for the same level of NOx controls on Unit 1.

Stanton Station currently projects spending approximately $10 million for a DSI system in order to comply with the BART SO_2 limit. NOx costs are contingent upon pending research and could range from $3.3 million to less than $1 million, depending on the final configuration.

In 2018, NDDH is expected to start the second round of regional haze reductions. Cost-effective controls and associated visibility improvements will again be determined for all emission sources in the state, with an expected compliance date of no later than 2023 for any applicable control requirements.

4.5 Transport Rules

EPA has promulgated a series of rules (categorically referred to as "transport rules") designed to address the transport and contribution of upwind states' emissions to nonattainment of National Ambient Air Quality Standards in downwind states. All of these rules have been challenged in court and remanded back to EPA. The latest remanded rule, the Cross -State Air Pollution Rule (CSAPR), was finalized by EPA on July 6, 2011. When the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded CSAPR on August 21, 2012, it left a temporary replacement, the Clean Air Interstate Rule (CAIR), in place until EPA addressed the court's order. CAIR is not applicable to Minnesota or North Dakota so it does not impact any GRE facilities.

On April 29, 2014, in a 6-2 ruling, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals and sent CSAPR back to the D.C Circuit. The Supreme Court did not address many of the technical corrections needed to fully implement CSAPR and instead left them for the D.C. Circuit. On June 26, 2014 EPA filed a motion with the D.C. Circuit to lift the stay on CSAPR. On October 23, 2014, the D.C. Circuit lifted the stay and compliance will begin on January 1, 2015.

CSAPR covers GRE's power plants in Minnesota but not in North Dakota. For our Minnesota generation facilities, GRE expects to operate within allowances as allocated by CSAPR, without needing additional controls. Allowances will be tracked with existing monitors at our peaking plants.

If these units operate in response to unexpectedly high peak demands and emit more than projected allowance allocations, GRE will purchase additional allowances as applicable. GRE's peaking turbines operate mostly on pipeline natural gas, which has inherently low sulfur content, or on ultra-low sulfur diesel as a back-up fuel. In addition, GRE's larger peaking plants are all equipped with dry low-NOx burners to control NOx emissions. No additional controls are expected in order to comply with these requirements.

4.6 National Ambient Air Quality Standards

Minnesota and North Dakota are currently in attainment with the National Ambient Air Quality Standards (NAAQS). EPA sets the standards for particulate matter (less than 10 microns or less than 2.5 microns), sulfur dioxide, nitrogen dioxide, and ozone, among other criteria pollutants. EPA then periodically re-assesses the standards and issues new standards that are protective of human health (primary) and the environment (secondary), with an adequate margin of safety. Upon issuance of the new standard, EPA provides guidance to the states on how they must assess their attainment status for the NAAQS. In response to EPA's standards, states each submit a state implementation plan to maintain attainment with the NAAQS and/or to bring a non-attainment area into attainment, as applicable. Depending on the area of non-attainment and the pollutant of concern, there can be several control methods to address the non-attainment, as determined by the state. EPA is now requiring more modeling demonstrations where monitors do not exist to assess attainment status. Understanding that models are inherently conservative, it is possible that more areas around the country will be considered as non-attainment, as states assess their attainment status and develop their respective implementation plans. Since state attainment demonstrations have not yet been developed, it is purely speculative to project any potential plant impacts at this time.

Nevertheless, GRE has been working with stakeholders to better understand the models, which will be used for attainment demonstrations, and has provided plant operational information to support state attainment efforts.

4.7 Mercury and Other Hazardous Air Pollutants

Since the early 2000s, GRE has been an industry leader in researching mercury reduction technologies at our plants. We have worked with the Electric Power Research Institute, U.S. Department of Energy, Lignite Research Council and University of North Dakota's Energy & Environmental Research Center, among others, to identify and test novel mercury reduction technologies. As a result of more than a decade of collaborative research, GRE is uniquely positioned to respond to EPA's MATS rule in a cost-effective manner.

In February 2012 EPA published its final MATS rule for electric generating units, which took effect on April 16, 2012. The rule establishes emission limits for essentially four categories of hazardous air pollutants: mercury, non-mercury metals, acid gases and volatile organic compounds. Utilities have three years to comply with the rule (i.e., April 2015). We recognize the rule provides for a relatively tight timeframe for design and construction of controls. Employees at our North Dakota generating plants have been working diligently on control strategies required by the MATS rule and fully expect to have cost-effective controls installed and operational by the compliance deadline.

As recently as late 2013 and early 2014, Coal Creek Station engineers completed some testing that identified a novel scrubber additive to control mercury in conjunction with boiler chemical additives. This research ultimately will save capital costs associated with installing a more traditional activated carbon injection system. Our plant engineers believe less than $1 million is now needed to comply with the MATS mercury limit.

Stanton Station recently contracted for installation of an activated carbon injection system, and is on schedule to install and commission the system before the MATS compliance deadline.

Spiritwood Station installed a carbon injection system as part of initial construction. It will be ready to control mercury, consistent with the MATS timeline.

With respect to other MATS pollutants, all three plants will meet acid gas requirements through inherently low chlorine coals (lignite and Powder River Basin), and as documented by quarterly emission testing or through surrogate SO_2 monitoring with existing plant monitors. With respect to non-mercury metals, each plant will maintain compliance with the particulate matter limit of 0.03 lb/MMBtu through existing highly-efficient particulate controls such as baghouses and electrostatic precipitators. No additional capital costs are expected to comply with these other non-mercury MATS requirements.

In summary, the MATS rule does require capital investment at our power plants. Due to our entrepreneurial, collaborative and innovative research efforts, the overall capital cost for MATS compliance at Coal Creek Station is expected to be less than $1 million. Stanton Station has also benefited from research efforts and is expected to incur an estimated $3 million in capital cost for activated carbon injection systems.

4.8 National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters

The “Boiler MACT” rule was finalized in March of 2011, and was subsequently updated by EPA in January of 2012. GRE has three sources that are subject to these requirements; they are auxiliary boilers located at Coal Creek Station and Stanton Station. Both of these plants have requested “limited use” restrictions at 10 percent of capacity, as part of their Title V air quality permit renewals. Once the capacity limits are incorporated into each plant’s Title V air quality permit, they will only have periodic tuning requirements in addition to some fuel flow tracking. This rule does not require any significant capital investment at GRE facilities.

4.9 Aquatic Life Protection at Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of a cooling water intake structure (CWIS) reflect the best technology available for minimizing environmental impact including threat to aquatic life. On August 15, 2014, as part of a settlement agreement, EPA published a final rule covering CWISs on existing facilities that withdraw from waters of the U.S. greater than two million gallons per day of which more than 25 percent is used for cooling. We are in the process of evaluating applicability of the rule’s impingement and entrainment requirements to Coal Creek Station, Stanton Station, and Elk River Energy Recovery Station. This evaluation will require input from the state environmental regulatory agencies.

Currently Stanton Station and Elk River Energy Recovery Station have completed initial strategy analyses for compliance with the new rule and are conducting baseline and limited planning exercises based on available information. Stanton Station has also conducted baseline impingement monitoring.

4.10 Effluent Limitations Guidelines

Under the Clean Water Act, EPA establishes national technology-based regulations, called effluent guidelines, to reduce discharges of pollutants from industries to waters of the United States and publicly owned treatment works. The guidelines requirements are incorporated into discharge permits issued by EPA and states. The Clean Water Act also requires EPA to periodically review and revise, if appropriate, the effluent limitations guidelines that have been established for an industry. The steam electric effluent limitations guidelines apply to steam electric power plants using nuclear or fossil fuels, such as coal, oil and natural gas. We operate in states where regulatory authority under the program is delegated to the state that implements the NPDES program in conjunction with its specific water quality protection requirements.

In 2010 EPA sent an Information Collection Request to all coal-fired electric generating units and a subset of generating units using other fuels concerning effluent limitations guidelines. These requests included Coal Creek Station and Stanton Station. EPA used the collected data to develop proposed revised effluent limitations guidelines for electric generating facilities.

A proposed effluent limitations guidelines rule was published on June 7, 2013. EPA received a large number of comments on the proposal. EPA is currently reviewing public comments on the proposal as it works towards a final action on the rulemaking. Pursuant to the terms of a consent decree, the EPA Administrator must sign a final action on the rule no later than September 30, 2015.

Revision of these guidelines could lower existing permit limits and introduce new analytical parameters required during sampling water discharges. The adoption of the new limits and parameters may result in additional monitoring expense and is likely to require additional or alternative treatment technologies for some pollutants.

GRE continues to monitor effluent limitations guidelines rules development and assess potential impacts to our facilities. The proposed rule outlines four preferred alternatives for regulation of discharges from existing sources. The impacts to GRE's operations will be dependent on which of the four options are chosen in the final rule.

The proposed rule places an emphasis on the elimination of handling wet fly ash. GRE does not have a facility that generates or manages wet fly ash and will be unaffected by this major component of the rule. Stanton Station generates wet bottom ash, which is not prohibited under most of the preferred regulatory options.

Coal Creek Station is a zero liquid discharge facility and does not have an individual NPDES permit. Any of the four preferred regulatory options will have little or no impact on operations at Coal Creek Station.

Spiritwood Station will discharge all of its wastewater to a publicly owned waste water treatment plant. The additional requirements, if any, remain unclear and will be further evaluated when EPA publishes a final rule.

All of our required NPDES and storm water permits are currently in place. We do not anticipate any major expenditures or operational modifications based on the adoption of the final rule.

4.11 Coal Combustion Residuals

GRE has actively pursued beneficial reuse opportunities for the coal combustion products generated at Coal Creek Station and Stanton Station. These efforts help offset the operating costs and environmental impact of our coal generation.

As a by-product of coal combustion, GRE generates approximately 520,000 tons of fly ash per year at Coal Creek Station. Historically fly ash was stored in landfills, but over the last 15 years GRE has been very successful in finding alternative uses for fly ash. Fly ash is primarily used as a partial replacement for Portland cement in concrete, which makes the resulting product stronger and more durable than concrete made with cement alone. It has also been used in other products. For example, fly ash was used in the backing of the carpet in GRE's headquarters building.

Beneficial use of ash in lieu of landfilling avoids cement production, reducing CO_2 emissions in the cement production process. For each ton of fly ash that is used as a cement replacement, GHG emissions are estimated to be reduced by approximately 0.8 tons. Since 1998 more than 2.5 million cumulative tons of CO_2 emissions have been avoided through beneficial use of GRE ash.

Stanton Station fly ash has been used to replace cement and scoria fines as a product to absorb the oil/water sludge created during oil well drilling and for soil stabilization. Stanton continues to improve upon its fly ash utilization in the oil field industry. No Stanton Station fly ash was landfilled in 2013.

Spiritwood Station is expected to begin commercial operations in the fourth quarter of 2014. The fly ash generated from Spiritwood will be marketed for beneficial use or disposed of in existing GRE disposal units.

Through the beneficial use of ash, GRE also avoids storing the ash in landfills, resulting in cost savings of over $7 per ton. Since 1998 over $22 million in cumulative landfilling costs have been avoided through beneficial use.

The beneficial use of fly ash may not continue. Recent developments could potentially disrupt the market for fly ash. The large release of fly ash, bottom ash and scrubber sludge from the Tennessee Valley Authority's Kingston Plant has brought renewed scrutiny of the disposal of coal combustion residuals (CCRs). EPA is considering options for regulating the disposal of all CCRs. One of their options is to regulate these materials as "hazardous waste" under Resource Conservation and Recovery Act (RCRA) Subtitle C or some variant. The results of this form of regulation could be far reaching. A RCRA Subtitle C listing would require significantly different facility designs and greatly increase the cost of disposal. It could also impact the market for ash. Consumers and sellers could be adverse to the risk of handling a material with potential RCRA Subtitle C liabilities. In some states, including Minnesota, it could make the use of the materials illegal. EPA is also considering regulation of CCRs under Subtitle D, which could involve more stringent landfill and monitoring requirements in addition to the potential need to convert from wet to dry handling.

The CCR rule is not expected to be finalized in 2014. Under the terms of a consent decree entered by the U.S. Court of Appeals for the District of Columbia Circuit on January 29, 2014 EPA is required, by December 19, 2014, to sign for publication in the *Federal Register* a notice taking final action with respect to EPA's proposed option to regulate CCRs as "non-hazardous" under Subtitle D. The consent decree does not require EPA to adopt Subtitle D regulations, but only requires EPA to make a final decision on whether or not it will adopt Subtitle D regulations by the set date. As EPA is a signatory to the consent decree, it is widely anticipated that EPA will finalize a "non-hazardous" Subtitle D waste option for the management of CCRs. This is the utility industry's much-preferred option and would result in minimal impact to our operations and associated costs.

GRE does not anticipate significant operational cost increases as a result of the pending CCR rule. Coal Creek Station and Stanton Station operate waste disposal facilities that currently comply with many of the design and operational requirements contained in the proposed subtitle D option. Any future landfill expansions would be built to comply with the revised regulations.

4.12 Phase-out Rule for Polychlorinated Biphenyls in Electrical Equipment

EPA is expected to propose polychlorinated biphenyl (PCB) phase-out rules in the fourth quarter of 2014. The revised rules will amend the use authorizations for electrical equipment so that, by a yet-to-be-identified date certain, "known" PCB- and, potentially, PCB-contaminated transformers may no longer be used. EPA is also considering a phase-out date for other types of PCB electrical equipment.

While it is not known exactly what equipment and end date will be targeted, GRE has been planning for the eventual PCB phase-out for some time. We have removed all testable equipment containing PCBs from our substations. The 4,224 PCB capacitors that support our HVDC converter stations have been the subject of a five-year phase-out effort that began in 2011 and will conclude by 2015.

The only other known pieces of PCB equipment are 103 transformers associated with electrostatic precipitators at Coal Creek Station. These transformers are scheduled to be removed during scheduled maintenance of the precipitators in 2016 or 2017. The costs associated with the removal and replacement of the PCB items does not represent a significant increase in operational costs for Coal Creek Station.

GRE continues to monitor the status of rule development.

5. CONSERVATION AND ENERGY EFFICIENCY PROGRAMS

GRE has long worked with our members to offer programs that encourage end-use members to manage electricity costs through conservation and energy efficiency improvements. Helping members use energy wisely not only reduces their costs, but also contributes toward more efficient, affordable and reliable electric service. We coordinate a portfolio of programs with our members to encourage homeowners and businesses to replace outdated, inefficient equipment with newer, efficient installations. Programs encourage members to pursue efficient alternatives ranging from small upgrades, such as compact fluorescent light bulbs and LED holiday lights, to large installations, such as ground-source heat pumps, variable frequency drives and manufacturing process improvements.

By fostering member relationships, our members are able to work cooperatively with their end-use members to educate, identify and implement energy efficient technologies that provide both energy and economic benefits to end use members. These efforts can have long lead times and require complex analysis to identify not only the economic benefits of energy efficient technology implementation, but also to ensure that the timing of major retrofits avoids unnecessary interruption to core business processes.

A key strength of our energy efficiency portfolios is the close relationships that our members have with their end use members, which enables a high level of awareness of energy efficiency opportunities and the delivery of cost-effective efficiency implementation.

Our portfolio of energy efficiency program offerings is informed by the end uses that are served by our member-owners. Electric end use within our member-owners’ service territories is dominated by residential consumers. Over 80 percent of our member-owner accounts are residential consumers. However, a significant percentage of the overall energy savings achievements are realized by large commercial, industrial and agricultural members.

5.1 Historic Achievements

Since 2010, our members have realized aggregate results that are in excess of the energy conservation goals that have been set by the Minnesota Legislature. Approval letters from the Minnesota Department of Commerce reflecting these savings are included in Appendix C: Conservation Improvement Program Approval Letters. Our annual savings for the 2008–2013 years are shown in Figure 5-1.

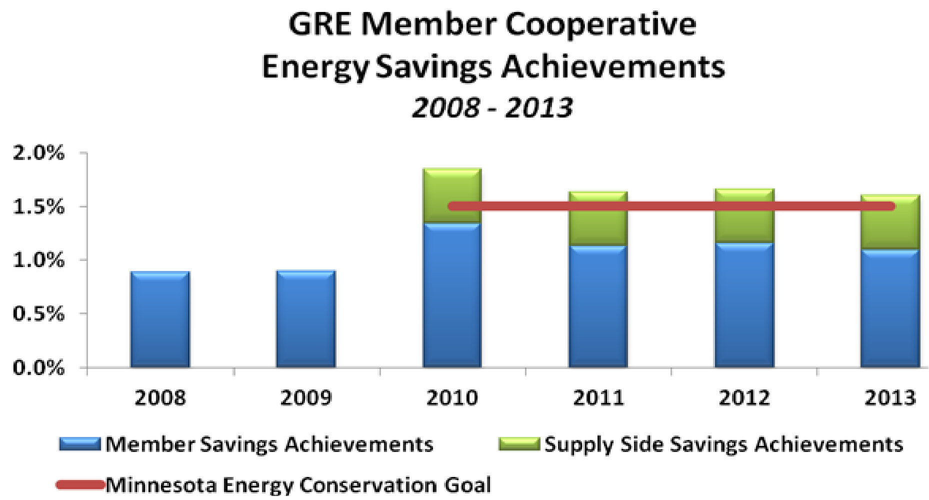

Figure 5-1. Energy savings achievements 2010–2013.

We are committed to working with our members and their end use members to build on the energy efficiency success of our members. Our ongoing efforts will continue to evolve during the forecast period.

5.2 Projected achievements in the forecast period

We have estimated total achievements over the forecast period to be 1.5 percent of total retail energy savings in each year of this IRP. We intend to accomplish this by continuing to drive energy savings equivalent to 1 percent through member side activities, while obtaining energy efficiency savings equivalent to 0.5 percent from investments in supply side efficiency throughout our and our members' systems. A breakdown of the anticipated energy savings achievements by member class throughout the forecast period is shown in Figure 5-2 below.

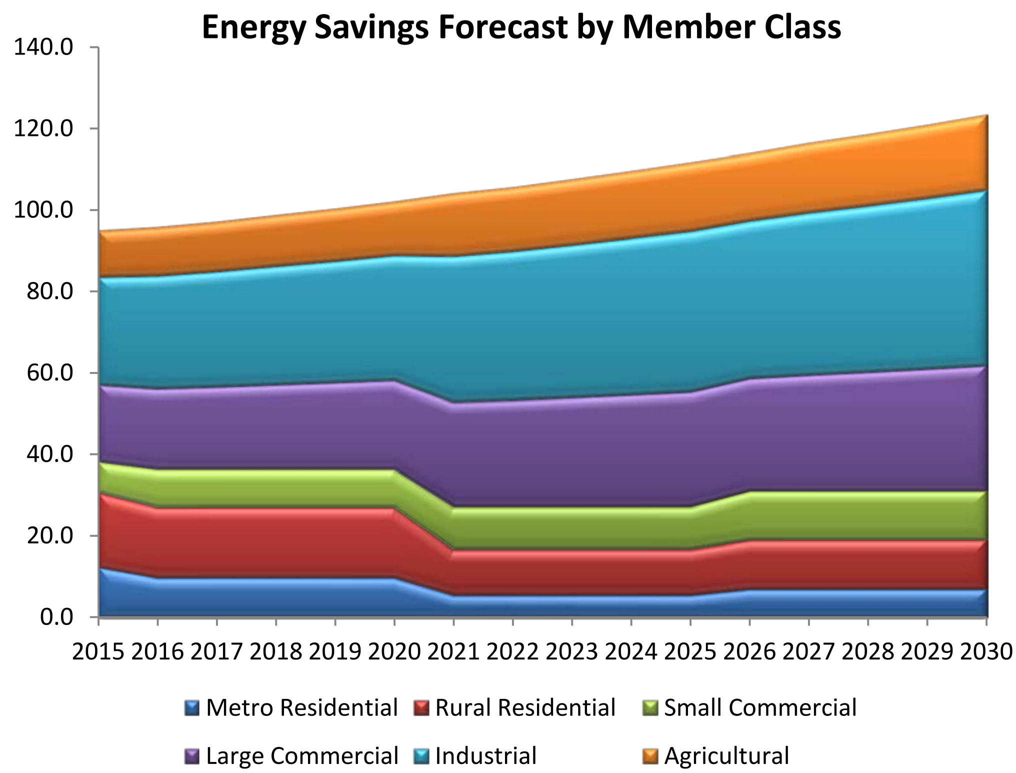

Figure 5-2. Anticipated energy savings achievements by member class throughout the forecast period.

To accomplish these goals, we plan to conduct the following energy efficiency program activities throughout the five-year action plan:

- Work with our members to identify and market new programs that improve awareness of energy consumption;
- Increase the adoption of efficient end use technologies where practical;
- Minimize rate impacts as a result of energy efficiency programs;
- Survey members to identify key electric end uses within homes and businesses;
- Participate in research to further characterize energy efficiency end use technologies; and
- Further evaluate the efficiency resource within our members' service territories.

5.3 Challenges to achieving the goals

While we and our 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:

1. Rural and residential nature of GRE’s members’ service territories;
2. Advancements in codes and standards, which limit both the number of opportunities and the incremental energy benefit associated with those opportunities;
3. Market transformation of efficient technologies; and
4. End use member investment appetites.

In addition to evaluating the energy savings associated with 1.5 percent achievement levels, GRE conducted an evaluation of meeting higher levels of energy savings, 1.25 percent, 1.5 percent, and 2.0 percent, while maintaining supply side savings in each scenario at 0.5 percent. This scenario analysis considered escalations to administrative and incentive costs, and evaluated the cost-effectiveness and potential rate impact associated with these various levels of achievement. Based on the results of this study, the current capacity need and the known challenges associated with increased levels of efficiency achievement, GRE is of the opinion that the proposed level of achievement is in the best interest of our member cooperatives. The results of this evaluation are included in Appendix D: Conservation Plan Scenario Analysis.

Rural and Residential Nature of GRE’s Members’ Service Territories

Total energy consumption per household is expected to decline as codes and standards progress and market forces encourage the adoption of energy efficient technologies. As shown in Figure 5-3, GRE’s system is dominated by residential sales. The majority of GRE’s members have residential sales that are in excess of 60 percent of their 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 compact fluorescent lamps, has yielded a sizeable percentage of the total energy savings achievements by all of GRE’s members.

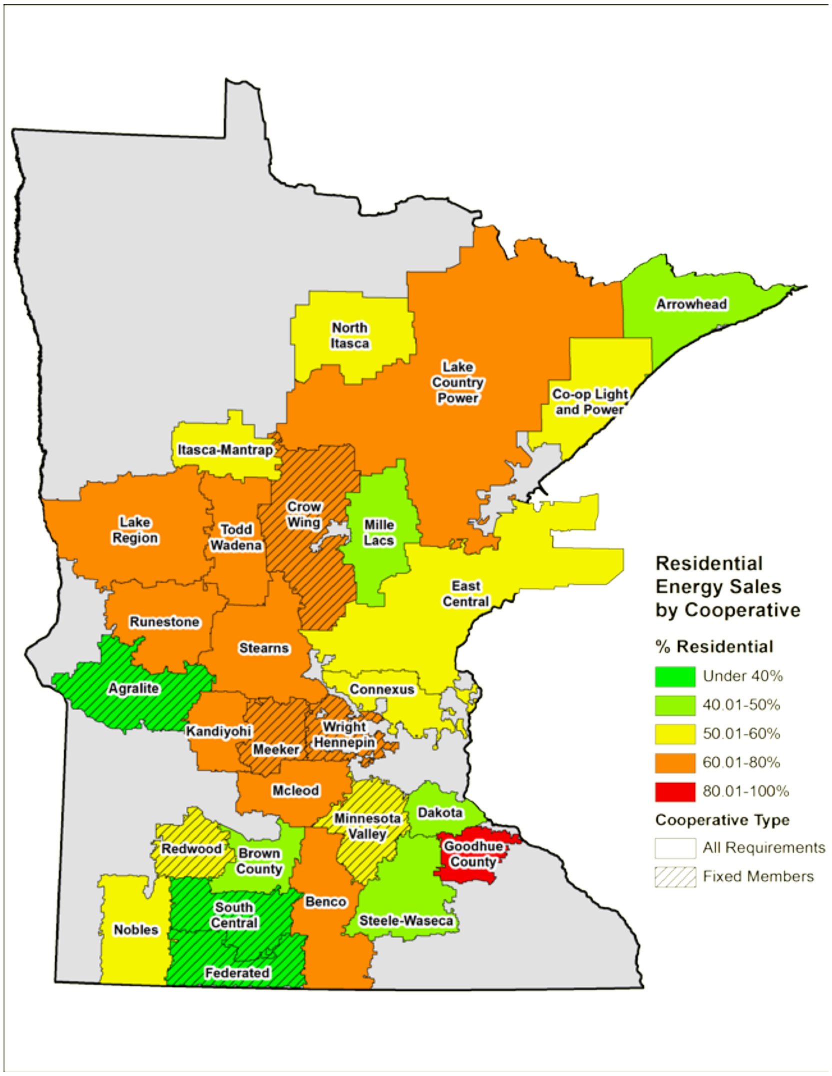

Figure 5-3. GRE members' service territories and percent residential energy sales.

Advancements in Codes and Standards

Many of the primary end uses that comprise major residential end use have been the target of federal efficiency standards over the past several decades. One piece of federal legislation that has had the biggest impact to energy end uses in recent years is the Energy Independence and Security Act (EISA). Figure 5-4 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.

GENERAL SERVICE INCANDESCENT LAMPS					
Rated Lumen Range	Maximum Rated Wattage	Existing Wattage	Percentage Decrease	Minimum Rated Lifetime	Effective Data
1490-2600	72	100	28%	1,000	1/1/2012
1050-1489	53	75	29%	1,000	1/1/2013
750-1049	43	60	28%	1,000	1/1/2014
310-749	29	40	28%	1,000	1/1/2014

Figure 5-4. EISA lamp categories.

Not only are the baseline technologies improving, which reduce the total energy savings that can be claimed by a utility program, but the efficient technologies have lifetimes that are significantly greater than those baseline technologies. This is particularly evident in the case of LED technologies, which have seen tremendous advancements in the performance and cost of manufacture of these programs, as well as the advances in the promotional delivery of these programs through major retailers.

The overall progress associated with these standards has an impact on the amount of savings that can be claimed, due to a reduced baseline from which energy savings are calculated, while the system impacts will be realized regardless of the ability to claim savings towards an energy efficiency goal.

Market Transformation of Efficient Technologies

End Use Member Investment Choices

Our energy efficiency resource is realized using an “all of the above” approach to member energy efficiency engagement. The total program is made up of four programs, which are described as follows:

1. **Equipment incentive programs.** These programs provide incentives for end use members 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 use members about their energy use and providing relevant comparisons that seek to illustrate ways in which end use members can reduce their consumption and lower their overall cost of energy. Several of GRE’s retail distribution cooperatives have employed tools like MyMeter, which presents energy consumption data through an online web portal, and OPOWER Home Energy Reports, which provide members with a report that highlights how their consumption compare to comparable members. In addition, several members have

employed direct appeals to members to reduce their consumption during the hottest months of the year. These "Beat the Peak" programs seek to have end use members voluntarily reduce their consumption and are associated with contests that reward members who realize the greatest reduction in their overall electric consumption.

3. **Supply side efficiency programs.** GRE and its members are leaders in identifying unique ways of improving the efficiency of generation, transmission and distribution of electricity. From the now commercialized DryFining™ process, which is being employed by generation facilities in China and Indonesia, to turbine upgrades, variable frequency drive (VFD) fans and pump applications, efficiency is often a central focus of 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.
4. **Market transformation.** GRE's long history of efficiency engagement with end use members has resulted in members that are well-versed in the benefits associated with investments in efficiency. As the market share of products that carry labeling indicating efficient products (e.g., ENERGY STAR) have expanded, many of the cooperatives end use members have adopted these technologies without taking advantage of rebate programs. This dynamic is evident from the results of our end use member surveys.
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 use to off-peak periods is most pronounced in the areas of electric storage water heating and electric vehicle charging efforts.

5.4 EIA Residential Energy Consumption Survey

The U.S. Energy Information Administration (EIA) is the statistical arm of the DOE. The EIA administers the Residential Energy Consumption Survey to a nationally representative sample of housing units. The most recent Residential Energy Consumption Survey was conducted in 2009 and captured data from more than 12,000 housing units that are statistically selected to represent the 113.6 million housing units that are occupied as a primary residence. While this data is not specific to any one utility, it offers useful insights for Demand Side Management planning purposes, especially when evaluated in conjunction with an individual utility's energy efficiency potential study and utility specific end use surveys.

Minnesota specific information from the Residential Energy Consumption Survey falls within the Midwest Division. The EIA has further split this division into two separate divisions, East North Central and West North Central. Minnesota is grouped into the West North Central Census Region and is aggregated along with three other states; Iowa, North Dakota and South

Dakota. An example of summary household data provided by the EIA is shown in Table 5-1 below.

Table 5-1. Table CE1.3 from the 2009 EIA Residential Energy Consumption Survey, Summary Household Site Consumption and Expenditures in Midwest Region, Divisions, and States – Totals and Intensities, 2009 British Thermal Units (Btu) and Dollars, Final.

Housing Unit Characteristics and Energy Usage Indicators	Total Housing Units[1] (millions)	Site Energy Consumption[2]				Energy Expenditures[2]			
		Total (quadrillion Btu)	Per Household (million Btu)	Per Household Member (million Btu)	Per Square Foot (thousand Btu)	Total (billion Dollars)	Per Household (Dollars)	Per Household Member (Dollars)	Per Square Foot (Dollars)
Total Midwest	25.9	2.914	112.4	45.1	49.5	51.34	1,981	795	0.87
Midwest Divisions and States									
East North Central	17.9	2.053	115.0	45.6	51.1	36.06	2,020	801	0.90
IL	4.8	0.613	128.8	50.7	58.9	9.84	2,067	814	0.95
MI	3.8	0.471	123.3	46.0	63.1	8.21	2,148	802	1.10
WI	2.3	0.235	103.2	43.8	39.6	4.38	1,926	817	0.74
IN, OH	7.0	0.735	105.0	42.4	44.8	13.64	1,948	786	0.83
West North Central	8.1	0.861	106.7	44.1	46.1	15.28	1,895	782	0.82
MO	2.3	0.234	100.2	40.4	42.7	4.43	1,892	764	0.81
IA, MN, ND, SD	3.9	0.442	113.0	46.9	46.6	7.61	1,947	808	0.80
KS, NE	1.8	0.185	101.7	42.7	49.5	3.24	1,786	750	0.87

One of the primary ways in which energy efficiency programs may be targeted to end use members is by evaluating key end uses and targeting those that have the highest overall cost-effectiveness. Through the 2009 Residential Energy Consumption Survey the EIA provides overall household end use consumption by fuel in the Midwest Region.

According to the data captured for the 2009 Residential Energy Consumption Survey the four state grouping that includes Minnesota had total energy consumption of 0.442 Quadrillion Btu, which is approximately 15 percent of the total U.S. consumption. Figure 5-5 illustrates the fuel breakdown for the state grouping that includes Minnesota.

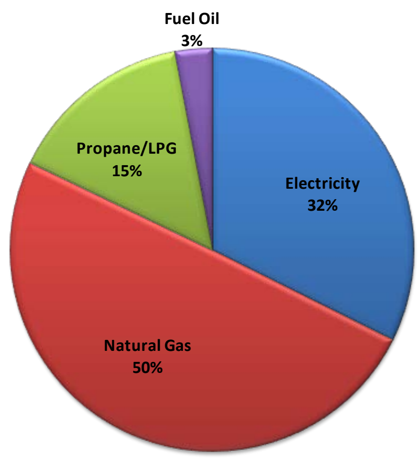

Figure 5-5. Fuel breakdown for the West North Central Census Division, IA, MN, ND, and SD.

Figure 5-6 illustrates the breakdown of electricity use by primary end uses. Space heating includes both primary and secondary space heating. The “Other” category includes end uses not shown separately, e.g. cooking appliances, clothes washers, dryers, dishwashers, televisions, computers, small electronic devices, pools, hot tubs and lighting.

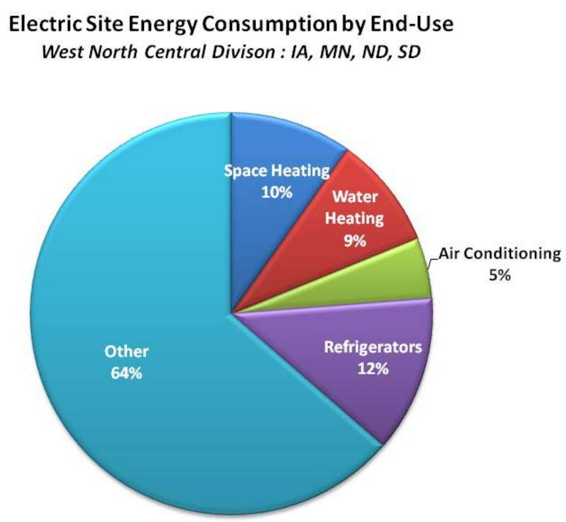

Figure 5-6. Breakdown of electricity use by primary end uses.

5.5 Emerging Energy Efficiency Technologies

Heat Pump Clothes Dryers

In 2013, the EPA recognized Advanced Clothes Dryers with the Emerging Technology Award in 2013. Information about this initiative is available at http://www.energystar.gov/index.cfm?c=pt_awards.pt_clothes_dryers_advanced_dev.

Advanced clothes dryers present a significant electric savings opportunity compared to other appliance categories. Clothes dryers represent one of the biggest instantaneous demands on the electric system, having a total electric demand draw of 4.5 kW. The EPA states that approximately 80 percent of the dryers sold in the U.S. are electric, and more than 6.5 million dryers are sold annually.

Given the nature of GRE's system loads, being predominately residential, combined with a system peak that typically occurs after 6 p.m., clothes dryers represent a strategic efficiency opportunity. However, the cost and commercial availability of heat pump clothes washers precludes this technology from adoption by many end use members. As this technology continues to develop GRE will work with its members to identify appropriate programs and incentive levels that encourage adoption of this technology.

Electric Thermal Storage

Since 1980 GRE, in cooperation with its members, has worked to offer larger capacity storage water heating as an overall cost-saving strategy for end use members. The program requires the use of large capacity water heaters, typically 80 gallons and larger, which enables the water heaters to consume electric energy between the hours of 11 p.m. and 7 a.m. each night. This strategy satisfies the hot water needs of end use member participants and enables the purchase of a large amount of off-peak electricity. The savings associated with these purchases are passed along to our members and their members. Currently 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 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 kWh in large capacity water heaters without a negative user experience effectively makes the ETS water heater program a very large system battery. On average GRE and its members store more than 845,000 kWh via ETS water heaters each night, increasingly many of these kilowatt hours are generated by renewable resources.

GRE has been engaged in testing various communications technologies that could enable Electric Thermal Storage 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. GRE has been working closely with providers of the control systems as well as working to determine the necessary ancillary services requirements that would need to be in place to enable this strategy. Currently GRE is piloting the effort with a small number of units in Lake Region's service territory, while the grid operator PJM is piloting the strategy within their service area as well.

GRE has been working closely with the NRECA, PJM, the American Public Power Association, Steffes Corporation, and the National Resources Defense Council (NRDC) to identify an option to continue offering ETS water heating programs to end use members. GRE will continue to work on regulatory and legislative solutions that will enable the continued operation of its ETS water heater programs, which provided very valuable system benefits and enable end use members to realize the monetary savings associated with the purchase of low-cost, off-peak energy.

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 that is utilized by 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. In Minnesota most of the water heaters 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 GRE's 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, the elimination of the ability 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.

GRE's 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. GRE has limited experience with applying load control to HPWH technologies. A short pilot that was 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. GRE continues to work with researchers such as the Electric Power Research Institute and the Cooperative Research Network to identify the best means of integrating HPWH technologies into its system.

Assuming there are no changes to the federal water heating standards, GRE is prepared to continue to evaluate options for its ETS programs. Certainly, GRE will see a continuation of program operation from 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; this will force members to adopt either 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.

5.6 EPRI Energy Efficiency Potential Study

Between 2010 and 2011, GRE worked with the EPRI to develop an estimate of the energy efficiency resource potential in GRE's service territory. The EPRI Energy Efficiency Potential Study analyzed energy efficiency potential of three member sectors: metro residential, rural residential 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 GRE's member energy efficiency program efforts.

The results of the EPRI analysis have been incorporated into the analysis of energy efficiency potential achievements, which has helped GRE to identify those end uses that offer the greatest potential for energy efficiency investment by end use members. The analysis by end use provides good insight into the program offerings that are most appropriate for GRE's member end users.

Throughout the forecast period we will 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.

5.7 2012 IRP Commission Order Point on Energy Efficiency and Conservation Program Offerings

In its September 26, 2013, Order in the Matter of GRE's 2012 Integrated Resource Plan the Commission included the following Order Points with respect to GRE's energy efficiency and conservation program offerings:

- Order Point 2.A. GRE should continue striving to save energy equal to 1.5 percent of its annual retail energy sales in a cost-effective manner; and
- Order Point 3.A. GRE should include an evaluation of potential conservation measures that it does not include in it its Conservation Improvement Program portfolio – including, at a minimum, all the measures identified in the Electric Power Research Institute study that pass the Total Resource Cost test.

In response to Order Point 2.A., GRE has continued to sustain its success in realizing energy efficiency achievements equal to 1.5 percent of its annual retail energy sales in a cost-effective manner. GRE's 2013 energy efficiency achievements were 1.1 percent from members' efficiency investments. We continued to utilize supply side energy efficiency benefits to meet the overall 1.5 percent goal. These figures are preliminary, as the Department of Commerce, Division of Energy Resources has not formally approved the 2013 savings. Formal approval is expected by December 1, 2014, as prescribed in Minnesota Statutes §216B.241, Subd. 1b. (g).

In response to Order Point 3.A., GRE continually evaluates its energy efficiency and conservation programs offerings based on several criteria. These criteria include, but are not limited to:

1. Ability to cost-effectively meet the Minnesota Energy Savings Policy Goal with the current portfolio of programs;
2. Primary energy end use drivers of its members;
3. Commercial availability of energy efficient technologies;
4. Energy savings treatment of energy efficient technologies; and
5. Member demand for new energy efficiency technologies.

The EPRI Energy Efficiency study identified a number of measures that passed the Total Resource Cost Test (TRC) in both the small commercial and residential sectors that the Commission did not believe were fully represented in GRE's current program portfolio. It should be noted that GRE has a number of mechanisms to encourage the installation of technologies that do not fall within a prescriptive program offering focused solely on that technology. This is true in the case of VRF Heat Pumps, which were one of the technologies that were identified within the study as passing the TRC. Due to the limited market penetration of these technologies, we believe it is inappropriate to formalize a program under which this technology would be the sole focus. As such, if there is members' interest in pursuing the installation of such a technology, GRE, in consultation with our members, is able to provide customized incentives that appropriately incent the technologies based on the expected performance and savings that are associated with their implementation.

Another consideration that will relate to the inclusion of technologies within GRE's energy efficiency and conservation program offerings is the overall availability of technologies that meet these standards. Another example of a technology that was identified within the EPRI study was the CO_2 Heat Pump Water Heater having an energy factor of 4.0. Currently there is no such product available for purchase in the U.S. This technology was considered in the planning study due to the expectation that it would be available to U.S. consumers within the timeframe that was considered in the study.

GRE works directly with individual members to identify those programs that are appropriate for their end use members. Individual members' characteristics will dictate the level of interest in one program or another, based on the member classes present (e.g. percentages of residential, commercial, industrial and agricultural members) as well as how each member allocates its budget to energy efficiency programming. While GRE develops the individual programs and program metrics, individual program implementation is ultimately driven by member demand for those programs.

Appendix E: EPRI Total Resource Cost Test Analysis includes the technologies that were identified as passing the Total Resource Cost test within the GRE EPRI Energy Efficiency Study along with the status in GRE's energy efficiency and conservation program offerings.

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6. DISTRIBUTED ENERGY RESOURCES

GRE and our members continue to evaluate the technical and cost impacts of on-site Distributed Energy Resource (DER) systems. We expect our members may introduce or utilize DER systems over the forecast period, particularly solar energy.

6.1 Evaluation of DER in the Planning Process

We have evaluated the potential impact of 1.5 percent customer owned photovoltaic energy resources on our system by developing an alternate forecast that reflects this additional generation on our system. We used the alternative forecast as a sensitivity in our modeling. The result of that sensitivity analysis showed a reduction in member energy requirements, but no change in the Preferred Plan under expected prices and expected growth.

6.2 Current Initiatives

GRE is working collaboratively with many stakeholders, with the goal of developing an understanding of DER benefits and costs that will inform fair, enabling policies and optimum levels of DER deployment.

GRE is investigating benefits and costs of distributed energy resources through several initiatives:

1. EPRI Integrated Grid Initiative. GRE supports EPRI's research, development and demonstration activities, including distributed generation integration. DG that exists today in the U.S. is interconnected to the grid, but is not fully integrated. Integration enables all the values of DG (e.g., resiliency, voltage support, emissions reductions, and distribution optimization) and allows all electricity users to fully benefit from DG deployment. EPRI is on a fast track (results by end of 2014) to develop a benefit/cost framework, establish interconnection guidelines and establish best practices for incorporating DG into grid planning and operations. GRE financially supports this initiative and has staff dedicated to utilize the findings in its planning and operations and those of its members.
2. DOE SunShot Initiative Solar Business Model (ISBM). GRE, Dakota Electric Association and Steele-Waseca Cooperative Electric partnered with RMI to explore community solar's significant opportunity for cooperatives to provide solar energy to its members, even at a time when resource additions aren't projected for the foreseeable future. The ISBM initiative's objectives will provide guidance on pricing that enables recovery of fixed costs and ensures fairness among members; utilize solar as a grid resource and

optimizing net value; target soft cost reductions; encourage high levels of customer adoption; enable scaling and replication to other cooperatives and utilities. As a result of this initiative, cooperatives can start offering community solar now, utilizing design elements that will seek to capture solar's full value while meeting all member consumer's expectations.

3. DOE SunShot Initiative Solar Utility Network Deployment Acceleration (SUNDA). The DOE and the NRECA signed a cooperative agreement for a multi-state 23 MW solar installation research project that seeks to identify and address barriers to PV deployment at cooperatives. The DOE is providing $3.6 million, matched by a $1.2 million cost share from NRECA, the National Rural Utility Cooperative Finance Corporation (CFC), Federated Rural Electric Insurance Exchange, and PowerSecure International, Inc. GRE is one of 15 participating cooperatives. Although targeted at larger installations, GRE will learn how standardization can help bring down the "soft" costs – labor, procurement, supply chain and other costs – of PV installations and reduce uncertainty about the effects of these installations on the distribution and transmission system.
4. GRE Research and Demonstration and Member Demonstration Projects. GRE and our members will construct more than 630 kW of new solar energy installations by mid-2015. The first construction project was a 250 kW solar array located south of GRE's headquarters facility. The facility includes a mix of technologies to help determine how solar energy installations can be integrated into cooperative systems. The remaining 380 kW may include up to 19 individual projects located in our members' systems across the state.

   Installing these solar panels will provide GRE and our members with experience in solar development. These projects will also help us identify solar technologies that are effective with our electric systems and local environment. GRE is working with our members to identify potential sites for 20 kW solar installations in their communities. The facilities are expected to be in service by mid-2015. These projects expand on GRE's commitment to developing renewable energy sources for our members.
5. Minnesota CHP Stakeholder Process. This process is DOE funded effort to carry out a strategic stakeholder engagement process and develop an action plan for CHP. The process grew out of a previous effort to evaluate ways to promote greater efficiency among the industrial sector in Minnesota, which identified CHP as a possible opportunity, but recognized that additional work was necessary to identify policies that would remove barriers to CHP implementation. GRE is involved to ensure that proposed policies are achievable throughout our members' service territories and to ensure there is not a negative rate impact to our member-owners.

6.3 Solar Projects under Development

GRE solar projects continue to take shape at member service territories throughout Minnesota.

Solar arrays are already generating electricity at GRE's headquarters and Dakota Electric Association, while systems are undergoing installation at Kandiyohi Power Cooperative and Lake Country Power. In addition to an existing 30 panel array in front of Kandiyohi Power Cooperative's facility, the cooperative also chose to build a 140 panel community solar array nearby.

Project installation at Kandiyohi Power Cooperative will be completed in October 2014, while the system at Lake Country Power is slated for completion by the end of 2014.

Construction will gear up on a few other solar projects in October and November at Cooperative Light & Power, Itasca-Mantrap Cooperative Electric – which will include a community array in addition to an 18 kW system package from tenKsolar – as well as East Central Energy and Nobles Cooperative Electric.

Details are still being worked out on projects planned to begin in 2015. These include Goodhue County Electric and Steele-Waseca Electric (April 2015); Brown County and BENCO Electric (May); Arrowhead Cooperative, McLeod and Todd-Wadena (June); Runestone and Stearns (July); and Mille Lacs Energy and North Itasca Electric (August).

These projects are in addition to large- and small-scale community solar arrays presently in place at sites in the service areas of Connexus Energy (245 kW), Lake Region Electric Cooperative (40 kW) and Wright-Hennepin Cooperative Electric Association (40 kW and 50 kW). Wright-Hennepin recently announced plans for a third community project.

GRE members who are installing community solar arrays had an opportunity to hear marketing tips from those who have already gone through the process. GRE hosted a "Solar Marketing 101" conference at our Maple Grove headquarters on October 8, 2014. Members attending this session learned what worked, what didn't and what these cooperatives wished they had done differently in marketing arrays to their customers.

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7. THE PLANNING PROCESS

GRE's long term resource planning is an iterative process that takes input from our strategies, expansion plan modeling, industry changes, environmental policy, regulatory and legislative requirements, our members, and our board of directors. GRE's board of directors determines the overall strategy for our organization and develops direction on our power supply portfolio, energy fuel types, and changes in greenhouse gas emissions regulations.

7.1 Our Approach to the Planning Process

Planning is an ongoing process. GRE's approach to resource planning is to develop a plan that is robust in meeting and balancing our objectives of cost-effectiveness for our members, reliable service, environmental stewardship, while meeting all state and federal regulations, and providing optionality as our members' needs evolve.

An enhancement to our planning process over the past year has been to engage external stakeholders and interested parties in our strategies and our planning process.

GRE developed this resource plan using the following planning process:

- Engage interested stakeholders;
- Determine modeling assumptions and requirements;
- Evaluate conservation and energy efficiency potentials;
- Estimate distributed energy resource impacts;
- 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 and DC line losses;
- Develop our load and capability position;
- Identify regulatory and legislative requirements, including externalities and regulatory costs;
- Allow our coal plants to be considered for retirement and coal contracts to be terminated in the modeling process if economic to do so;
- Model cases that include multiple sensitivities to identify potential expansion plans;
- 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.

7.2 External Stakeholder Outreach and Engagement

The last decade has been a time of change for the electric industry. GRE engaged Great Plains Institute to facilitate two discussions with external stakeholders that occurred over the course of several days. In the fall and winter of 2013/2014, GRE invited external stakeholders to a facilitated discussion process to talk about our business and the challenges we are facing, to understand their views on pressing issues, and to hear from our stakeholders on what they thought and expected of our organization. By welcoming the perspectives of end-use consumers, financial institutions, low-income advocates and environmental nonprofit organizations, we gained valuable insight into the priorities of those with a vested interest in cooperative electricity in Minnesota.

The goals of these meetings were to:

- Foster mutual understanding;
- Obtain feedback on GRE strategies; and
- Identify issues for our next strategic planning cycle.

At the conclusion of the meetings, stakeholders suggested GRE pursue the following strategies:

- Promote awareness of the benefits of the cooperative structure and member governance;
- Maintain focus on the mission to provide reliable, affordable electric service to members;
- Utilize existing capacity surplus to promote local economic growth;
- Coordinate with MISO on transmission planning;
- Continue leadership in development of regional transmission;
- Promote electrification and economic development;
- Keep cost at the center of strategic decisions;
- Embrace the idea that the economy should run on electricity, particularly as electricity continues to get cleaner;
- Publically communicate plans to reduce exposure to greenhouse gas regulation;
- Support a flexible, regional, market-based approach for greenhouse gas regulation;
- Expand energy efficiency and demand response by identifying market and regulatory opportunities;
- Include distributed generation in resource and transmission planning;
- Promote the fact that a strong electric grid is necessary for integrating high penetrations of distributed generation;
- Collaborate with member cooperatives and local agencies in developing distributed generation;

- Locate distributed generation where it makes economic sense; and
- Promote wind energy as a hedge against fuel price volatility and carbon regulatory risk.

In addition, GRE invited Great Plains Institute to facilitate a separate discussion with parties interested in the IRP process on May 15, 2014. At this meeting, GRE presented our mission to provide members with reliable energy at affordable rates in harmony with a sustainable environment, our cooperative governance and principles, our current generation portfolio, our success in greenhouse gas emissions reductions, development of new solar and distributed generation, leadership in potential regional CO_2 reduction strategies, and results from the previous stakeholder engagement process.

We talked about our activities to reduce our impact on the environment and comply with the following current and expected regulatory actions for MATS, coal ash, §316(b) (water intake), effluent limitations guidelines, PCB insulating fluids, CSAPR, and CO_2/greenhouse gases.

We also discussed the activities involved in developing a resource plan, including energy and demand forecasts, conservation, energy efficiency and demand response impacts and projections, existing generation resources, regulatory and statutory requirements, sensitivities on market prices, fuel costs and generation costs, and our board direction to evolve our resource portfolio.

Participants asked questions and made suggestions at the meeting and were also invited to send additional comments through email. Questions and suggestions were received on the following topics:

Forecasting

- End use analysis in addition to econometric modeling
- Electric vehicles, penetration and time of use rates

Demand side management, conservation and energy efficiency

- Resources in real time like Demand Response, storage, load forecasting
- New technologies such as Nest thermostats
- Technology change over time

Modeling and sensitivities

- Kinds of models and platforms used
- Modeling assumptions
- Testing single variables vs. several variables at a time
- Which variables make the most difference

Generation

- Carbon capture and sequestration
- Improvements in wind's capacity factor
- Modeling of wind and comparison with performance of actual wind resources
- Prices for new generation and source of the data
- U.S. Energy Information Association data lag by at least a year and may not be accurately capturing wind prices
- Production Tax Credit assumptions
- Solar costs
- Firm gas as a cost for gas fired generation

Minnesota energy policy, environmental compliance and Commission review

- Sensitivities on Minnesota's Renewable Energy Standard: 40 percent by 2030 and 50 percent that is 40 percent renewable and 10 percent solar
- Externality values
- Compliance with CO_2 regulations
- Regional approach vs. state-by-state implementation for CO_2 compliance
- Spokesperson, IRP presentation, and handling unexpected elements
- Feedback requested from the Commission

Energy market and MISO

- Products GRE could provide if market structures were in place, such as ancillary services
- The market as proxy for variable generation
- Dynamic and variable systems, which will require a different set of assumptions to accurately predict what may happen
- Products that include carbon management.

A summary of the comments was sent to all participants. We found that our resource plan development already included some of these ideas. We incorporated many of the new ideas into this resource plan. One example was the suggestion to use varying costs for wind energy in our modeling. In response, we conducted several sensitivities that included lower wind prices.

Another example of how we used this input in our modeling was the suggestion to incorporate multiple sensitivities in a single case to estimate different futures, rather than running a single sensitivity each time. In response, most of our cases that we ran in the model reflect multiple sensitivities combined. We also ran a case that reflected a 40 percent Renewable Energy Standard in 2030, as requested.

GRE continues to reach out to participants of both the stakeholder and the interested parties meetings. Ongoing information and involvement by all parties will help ensure we stay engaged with our stakeholders. A second meeting with interested parties was held on October 29, 2014 prior to the filing of this resource plan. At this meeting, we presented our strategies and initiatives, results of our modeling, our Preferred Plan, the relationship between GRE and our members, and other items from this IRP filing.

7.3 Modeling

Currently, GRE uses a Ventyx software product called System Optimizer™ to conduct modeling and analysis of resource expansion plan options, including adding or retiring generation resources. System Optimizer™ evaluates the need for future resources to meet demand by finding an optimal expansion plan. The model solves for the least cost expansion plan by identifying the Net Present Value of the Revenue Requirements (PVRR) over the study period, given the inputs and constraints used.

We work with internal GRE experts, members' experts, and consultants to gather assumptions that could affect our resource plans. These assumptions include inputs into energy and demand forecasting, conservation expectations, electric and fuel market price forecasts, costs, bi-lateral contracts, costs of potential new generation, and regulatory requirements. We review these assumptions and use the data to develop expected load forecasts and potential generation resource plans. We also analyze alternate assumptions as sensitivities that are included into the expansion model.

7.4 Model Inputs

The primary inputs to the model are:

- Our existing generation and contract resources;
- Energy and demand forecasts;
- Reserve margin requirements and MISO coincident peak and GRE system peak;
- Load and capability position;
- Coal retirement options;
- New generation resource options with varying levels of capital costs;
- Required ranges of environmental externality and carbon regulatory cost;

- Energy market interaction;
- Market energy and fuel price forecasts, and
- Renewable Energy Standard compliance and solar resources.

Other sensitivities of interest include varying penetration levels for conservation and energy efficiency, electric vehicles and distributed generation.

Existing Generation and Contract Resources

GRE owns and operates 12 power plants. We purchase additional power from several wind farms and other generating facilities. Our power supply portfolio offers more than 3,500 MWs of generation capability that consists of a diverse mix of baseload and peaking power plants, including coal, natural gas, hydro, wind, oil plants, and landfill and biogas.

Table 7-1 describes our existing resources by nameplate, MISO accredited capacity and fuel type.

Table 7-1. 2014-2015 existing generation resource ratings.

Existing Resources	Primary Fuel Type	Nameplate or ICAP (MW)	Planning Reserve Credit or UCAP (MW)
Spot Market Purchases	unspecified	400	N/A
Coal Creek	Refined lignite	1,163	1,109
Stanton Station	Powder River Basin Coal	187	183
Spiritwood	Refined lignite	99	89
Dairyland Power Cooperative (Genoa 3)	Powder River Basin Coal	N/A	117
Elk River Resource Recovery Station	Refuse-derived fuel	31	21
Cambridge 2	Natural gas	167	164
Elk River Peaking Station	Natural gas / fuel oil	163	153
Lakefield Junction	Natural gas / fuel oil	522	519
Pleasant Valley Station	Natural gas / fuel oil	418	386
St. Bonifacius	Fuel oil	56	44
Rock Lake	Fuel oil	19	19
Maple Lake	Fuel oil	19	18
Cambridge 1	Fuel oil	20	19
Small Diesels	Fuel oil	5	5
Arrowhead Emergency Generation Station *	Fuel oil	18	N/A
Trimont Wind Farm	Wind	100	14
Prairie Star Wind Farm	Wind	100	13
Elm Creek Wind Power Project	Wind	100	16
Ashtabula II Wind Energy Center †	Wind	51	0
Endeavor I Wind Energy Center	Wind	100	11
Other small wind	Wind	14	3
Biogas	Biogas	3	N/A
Cooperative Community Solar †	Solar	0.065	N/A
Western Area Power Administration	Hydro	N/A	81
Other bi-lateral contracts	unspecified	N/A	241

* Did not include in model as is only for transmission emergencies.

†No planning reserve credits due to non-firm transmission.

Nameplate, or installed capacity (ICAP), is the amount of capacity assigned to a resource which is the lesser of the resource's annual, seasonal or monthly net demonstrated capability and the net output identified in the capacity resource's Interconnection and Operating Agreement. Unforced capacity (UCAP) is the amount of capacity assigned to a planning resource after accounting for its forced outage rate or historic availability. MISO's Resource Adequacy construct accredits capacity based on UCAP. UCAP values have been used in our modeling.

All known and recent generation efficiency improvements have been included in our modeling assumptions. Scheduled maintenance and costs are also included in the model. We have not assumed future and as yet unknown plant efficiency improvements in the modeling.

For a trade secret list of generation and contract assumptions, including costs and emissions rates, see Appendix B: Generation Resources Characteristics.

Figure 7-1 illustrates our current UCAP generation capacity by fuel type. Figure 7-2 illustrates our 2013 energy production by fuel type.

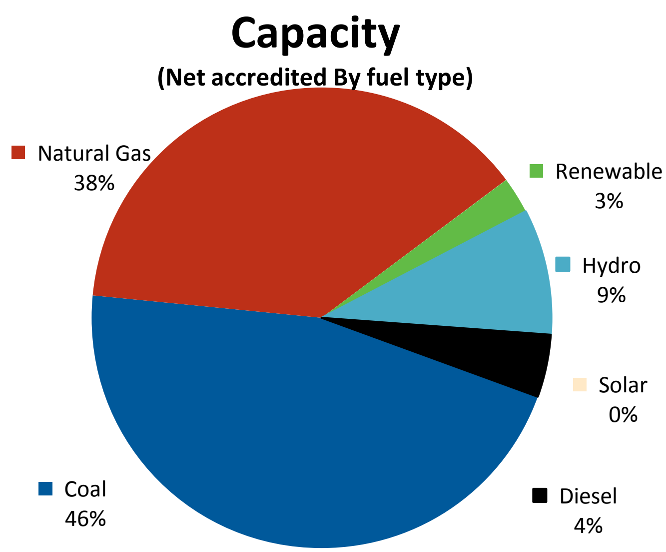

Figure 7-1. GRE's current UCAP generation capacity by fuel type.

Figure 7-2 illustrates our 2013 energy production by fuel type.

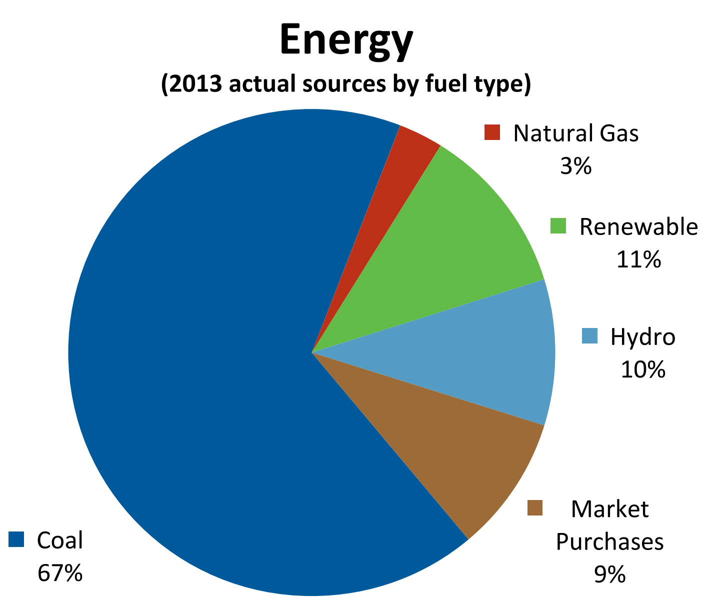

Figure 7-2. GRE's 2013 energy production by fuel type.

Energy and Demand Forecasts

GRE developed econometric forecasts for our AR members' energy and demand requirements. The system wide energy and demand requirements were then developed using the AR member forecasts and adding in Fixed member requirements, transformation and transmission losses and DC line losses. Historical load shapes were analyzed in the MetrixLT© software along with future day types (weekends and holidays) to transform the monthly energy and demand forecasts to hourly forecasts.

Sensitivities on the forecasts were developed to estimate high and low growth scenarios. These load forecasts were also transformed to hourly load shapes and input into System Optimizer™. See section 8 for detailed information on the forecast process.

Reserve Margin Requirements and MISO's Coincident Peak and GRE System Peak

GRE's load requirement is determined using MISO's Module E resource adequacy construct and MISO's Planning Reserve Margin. We compare our forecasted system summer peak demand and adjust the peak for coincidence with the MISO wide peak. Through an analysis of our system peak coincident with MISO's system peak, we have identified a 10 percent diversity factor. We then use this diversity factor and MISO's Planning Reserve Margin to identify our resource obligation in MISO.

GRE's base assumption is to continue participation in the MISO energy market and to plan to MISO's reserve requirements. We used a 7.3 percent planning reserve margin on a forecast that was reduced by a 10 percent diversity factor to determine the coincidence to the MISO peak load. This was applied in all but one case where we assumed energy market interaction. We also used the lower UCAP capacity resource ratings when planning to the MISO resource construct. In one case where we assumed energy market interaction and in all cases where we assumed no market interaction, we modeled planning reserve requirements as if we were planning to our own system peak load. In these cases, we used a 15 percent reserve requirement on our system peak load and used ICAP resource ratings. The one case that assumed energy market interaction, but planned to our system peak with 15 percent reserve margin, was intended to test a case where we reflect planning to our own peak rather than the MISO coincident peak, while still participating in the energy market.

Load and Capability Position

We aggregate the UCAP values of our owned and contracted generation resources as well as the owned or contracted resources of our members. We incorporate existing bilateral purchase and sales agreements. We assume existing bilateral agreements will expire at the end of their terms without renewal. We then compare the amount of generation available to the amount of resources needed using our coincidence with MISO's peak and MISO's planning reserve margin to identify our load and capability position.

Figure 7-3 illustrates the relationship between our load forecast and currently available generation resources over the forecast period. The black line represents our MISO resource obligation to serve our load. The blue area above the line means we have surplus capacity. If a blue column were to be below the line, it would mean additional resources are needed to meet our capacity obligations. Under our expected assumptions, we do not need new generation resources to meet our obligations over the 15-year forecast period. Figure 7-3 reflects our current load and capability position in 2014 before incorporating our Preferred Plan.

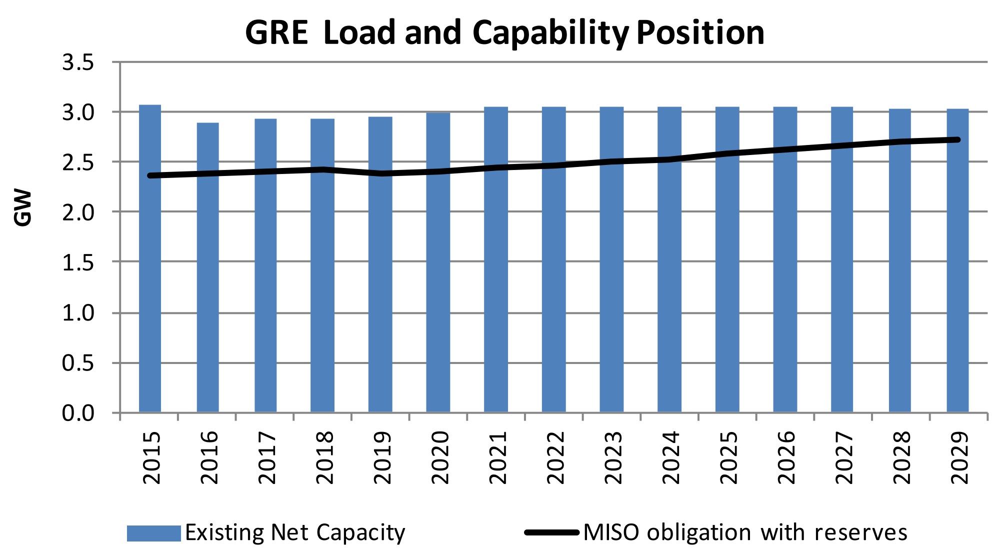

Figure 7-3. GRE's current load and capability position without the Preferred Plan.

Surplus capacity benefits our members in several ways. Having capacity above our requirements adds to the reliability of the MISO market. It also means we do not need to make large capital investments that would result in higher rates. We look for opportunities to sell some surplus capacity through bilateral transactions, and have made several such arrangements in the past few years. At the end of the transaction, the capacity returns to our members. Another benefit of excess capacity is that the capacity is available to the market to support intermittent resources when or if needed.

Resource Retirement Options

In response to Order point 3.C. of the 2012 Resource Plan, GRE changed the way our modeling is conducted so that we now consider generation alternatives in the modeling. The model has been refined to allow the selection of coal unit retirements or coal contract terminations if it makes economic sense to do so. Generation retirement options include fuel, variable operations and maintenance costs (VOM), total fixed costs, and projected shutdown costs. Total fixed costs include operations and maintenance, insurance, taxes and annual depreciation. Net shut down costs include remaining book value plus dismantling costs minus shutdown costs already accrued. Allowing the model to select generation coal units for retirement, in combination with varying levels of economic and regulatory assumptions, demonstrates the value of the coal units in the portfolio.

New Generation Resource Options with Varying Levels of Capital Costs

New generation and replacement generation options include natural gas fired peaking and combined cycle generation, hydro, wind and solar. We modeled all potential resources as potential capital investments with the exception of hydro generation. The U.S. Energy Information Administration (EIA), http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf and Lawrence Berkley National Laboratory, http://emp.lbl.gov/sites/all/files/lbnl-6610e-ppt.pdf, data are the source for the capital, fixed and variable costs for these potential resources. In addition, we added a cost estimate for transmission and interconnection, financing, taxes and insurance. Electricity market price forecasts provided the basis for new contracted hydro energy costs. Due to current and uncertain future regulatory constraints on coal, no new coal resources were offered as potential resources in the modeling. We included data for a natural gas combined cycle potential resource with carbon capture and sequestration (CCS) from EIA. Due to the high estimated costs, the model did not pick a unit with CCS.

Required Ranges of Environmental Externality and Carbon Regulatory Costs

GRE included cases with and without the application of Commission approved externalities and carbon regulatory costs. Geographic location determined how the externality costs were applied to generation. Starting in 2019, GRE applied the range of carbon regulatory costs established by the Commission to all generation unit emissions irrespective of geographic location, replacing the carbon costs associated with externalities. Externality and regulatory costs were increased by the CPI-U projection in the EIA's 2014 Annual Energy Outlook.

Table 7-2 below summarizes how carbon dioxide cost values are used in our modeling.

Table 7-2. Carbon dioxide cost values used in our modeling.

	Years before 2019 (Environmental Cost)	2019 and after (Regulatory Cost)
Power Generated Inside Minnesota	Used the \$0.43 to \$4.46 per ton range pursuant to Commission Notice dated May 22, 2014	Used the \$9 to \$34 range established pursuant to Commission Order dated April 28, 2014
Power Generated Outside Minnesota (regardless of whether it is more than 200 miles from the Minnesota border)	No added cost: Environmental Cost for CO_2 set at \$0.00 in Commission Notice dated May 22, 2014	Used the \$9 to \$34 range established pursuant to Commission Order dated April 28, 2014

Energy Market Interaction

In developing this IRP, we did not rely on the MISO market for capacity, since GRE has no capacity needs during the forecast period. In most of the cases examined, the model was allowed to interact with the energy market on an economic basis in a limited fashion. In the cases allowing energy market interaction, the size of that interaction was limited to 400 MWs per hour of purchases and/or sales. We also ran several cases that did not allow any market energy interaction at all.

Market Energy and Fuel Price Forecasts

Forecasts for the electric market and natural gas price sensitivities were based on a combination of near term broker quotes and a long term Wood Mackenzie forecast. The forecasts of the cost of coal for Coal Creek Station, Stanton Station, Spiritwood Station and Genoa 3 are based on internal estimates that best reflect our expectations for mining and contract costs. Sensitivities of low, expected and high market and fuel prices were also modeled.

Renewable Energy Standard Compliance and Solar Resources

Potential wind and solar resources were modeled as capital investments. The model was allowed to pick these renewable resources based on least cost. In cases where insufficient renewable resources to meet Minnesota's Renewable Energy Standard were selected as optimal, the model was then forced to add enough wind to meet all renewable energy requirements based on the expected load forecast. In addition, sensitivities were modeled with both wind and solar at costs 30 percent below published capital costs. Finally, a 40 percent renewable energy sensitivity was modeled to determine the additional amount of new wind and the potential cost of those additional renewable resources.

For this resource plan, we identified 32 combinations or cases to run in the model. A matrix of the combinations can be found in Appendix F: Model Sensitivities Matrix. The modeling results are discussed in Section 9.

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8. FORECAST

8.1 Residential Consumer Forecast

The Commission in its Order 2.C. in GRE's 2012 IRP Docket No. ET-2/RP-12-1114 , asked that GRE consider making changes to our forecasting process that reduces the need for adjustments to the residential consumer growth forecast. In response to this Order, we changed the way we conduct the residential consumer growth forecast such that external adjustments are not needed.

We no longer ask our members for their suggestions and recommendations on what the residential consumer growth forecast will be for their service territories. Instead, we have developed a strictly econometric forecast based on household forecasts of primary counties served and changes in the share of households served by our members.

This residential consumer forecast captures the housing market cycle and is driven by county-level household forecasts developed by the Minnesota State Demographic Center. We retained a third-party forecasting consultant to develop this independent analysis and forecast of residential consumer growth. As a result, no after-the-fact adjustments have been made by our members or by us to the residential consumer forecasts.

A comprehensive description of the forecast methodology, results, and conclusion can be found in Appendix G: Energy and Demand Forecast Methodology.

8.2 Historic AR Member Energy Sales and Peak Demand

GRE forecasts energy and demand for our AR members, and then adds on our Fixed customers' energy and demand to result in Total System energy and demand forecasts. The All-Requirement forecast methodology is described below.

The following information is an abbreviated summary of the methods and results of GRE's 2014 All Requirement Member Energy Requirement and Coincident Peak Demand Study. This comprehensive study can be found in Appendix G: Energy and Demand Forecast Methodology.

During the Great Recession and afterwards, GRE experienced a drop in energy sales and in coincident peak demand. Year-over-year AR member weather normalized energy sales were consistently more than four percent prior to 2008, and were then reduced to low of negative 1 percent in 2009 (Figure 8-1). Since 2009, GRE has made a steady recovery in energy sales.

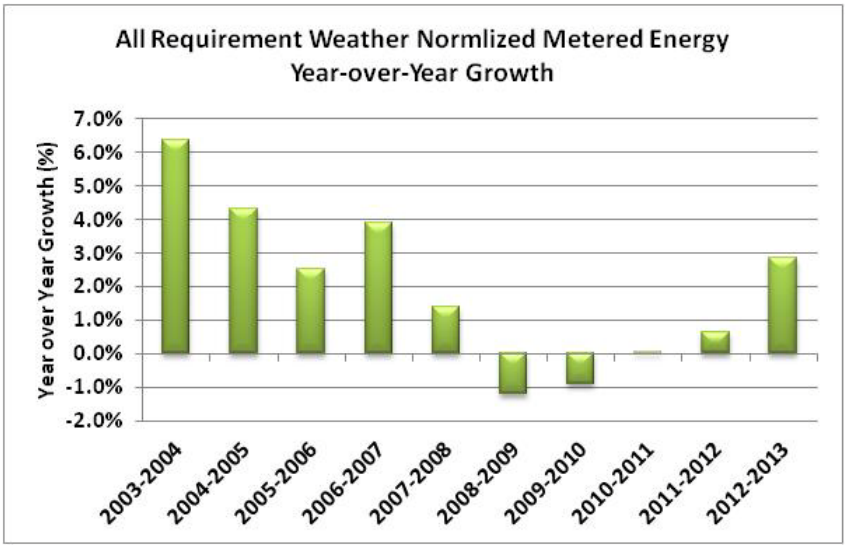

Figure 8-1. Historic weather normalized AR member energy sales.

One of the major causes of this energy and peak demand reduction was the crash of the housing market. GRE's largest customer class and energy class is residential consumers. GRE's energy sales and peak demand growth have always been dependent on the growth of the residential customer class. With the collapse of the housing market and the proceeding Great Recession, growth in our residential category was reduced from consistently being above 3 percent to slightly above zero percent (Figure 8-2).

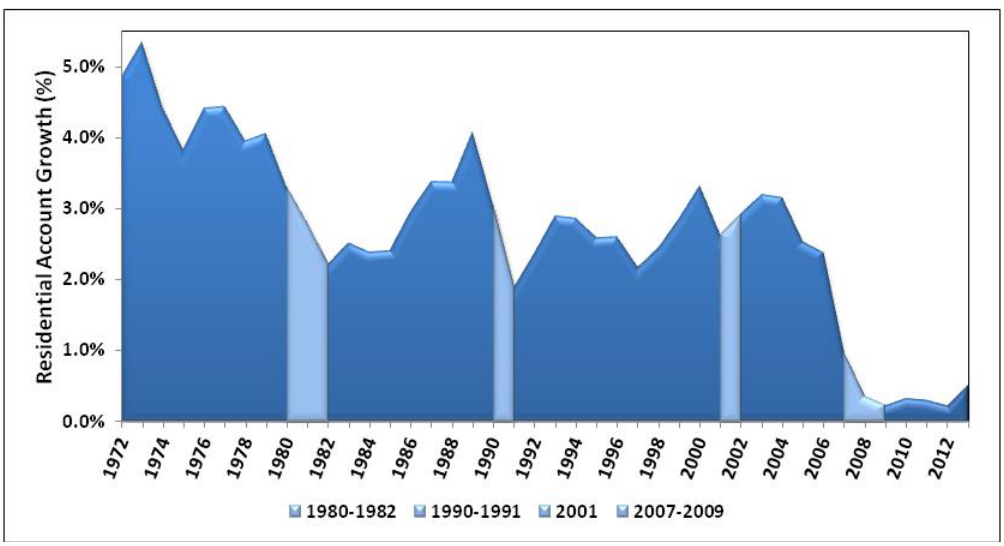

Figure 8-2. Historic GRE AR member residential account growth from 1992 to 2013.

Starting in 2011, year-over-year growth in Minnesota housing starts by building permits began to increase and our residential account growth began to respond accordingly (Figure 8-3). This uptick in building permits is leading to an increase in residential accounts and supports the weather normalized AR member energy sales observed in Figure 8-1.

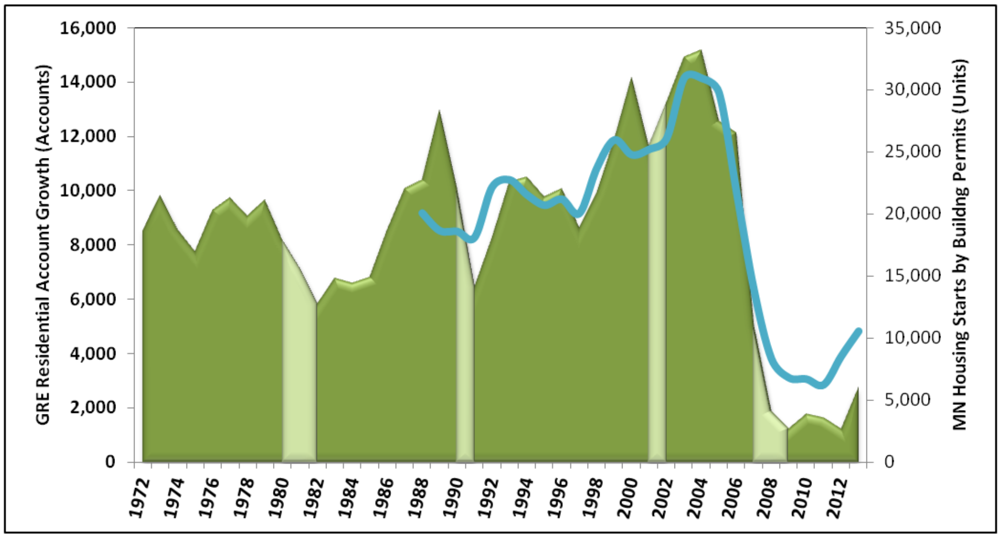

Figure 8-3. Comparison of GRE's AR member consumer growth and Minnesota private building permits (units).

8.3 Forecast Regions

Due to the geographic and economic diversity of GRE's membership, the 20 AR members were broken down into three distinct forecast regions. By breaking up 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.

8.4 Energy Regression Model Development

Description and Assumptions

GRE is owned by 28 member distribution cooperatives where 20 of our members are AR members and eight of the members are Fixed members. The Fixed members have entered into a long-term power purchase contract to purchase only a fixed amount of capacity and energy from GRE. For the remaining 20 members, GRE is responsible for all of their energy. *The following econometric forecasts are for the AR members only.*

Each of the AR members was assigned to one of three forecasts regions: Metro, Northern, and a combined Southern & Western. To calculate the combined AR and Fixed energy obligation, the Fixed Member energy amount will be added to the three aggregated regional forecasts.

Energy sales forecasts were developed using metered data with historic load control embedded in the data. An assumption is made that our historic load control program will remain consistent into the future, e.g., our historic growth in load control will continue to be the same growth going forward along with how these load control programs are implemented. All energy forecast results reflect load control.

Energy Regression Model's Structural Form

An annual energy model was fit using multiple linear regression techniques with MetrixND© for each of the three forecast regions. Depending on forecast region a combination of explanatory variable were considered to explain annual regional energy. The list of explanatory variables includes:

- Residential consumers;
- Employment;
- Cooling degree days;
- Heating degree days;
- GRE wholesale member rate;
- Employment-to-population ratio; and
- Residential propane price.

A description of each of the forecast region's energy model's structural form and explanatory variables are as follows:

Metro Region

$$\begin{aligned}\ln(Annual\ Metro\ Region\ Energy) &= \beta_0 + \beta_1 \ln(Metro\ Region\ Residential\ Consumers_{-1}) \\ &+ \beta_2 ln(Metro\ Region\ Employment_{MA_2}) + \beta_3 \ln(Metro\ Region\ CDD_{65}) \\ &+ \beta_4 \ln(\text{Wholesale Rate Real}_{\text{MA}_3})\end{aligned}$$

Where:

β_0 = Constant/y-intercept,

β_1 = Natural Log of Metro Regions Residential Consumers lagged one-year,

β_2= Natural log of Metro Region's Employment, two-year Moving Average,

β_3 = Natural log of Metro Regions Cooling Degree Days, Minneapolis basetemp 65 and

β_4 =Natural log of GRE's Wholesale Rate Real, three-year Moving Average.

Northern Region

$$\begin{aligned}\ln(Annual\ Northern\ Region\ Energy) &= \beta_0 + \beta_1 \ln(Northern\ Region\ Residential\ Consumers_{-1}) \\ &+ \beta_2 ln(Northern\ Region\ HDD_{65}) \\ &+ \beta_3 \ln(Northern\ Region\ Employment: Population\ Ratio) \\ &+ \beta_4 \ln(\text{Wholesale Rate Real}_{\text{MA}\,3})\end{aligned}$$

Where:

β_0 = Constant/y-intercept,

β_1 = Natural log of Northern Regions Residential Consumers lagged one-year,

β_2= Natural log of Northern Regions HDD, Hibbing MN basetemp 65,

β_3 = Natural log of Northern Regions Employment-to-Population Ratio and

β_4 =Natural log of GRE's Wholesale Rate Real, three-year Moving Average.

Southern & Western Region

$$\begin{aligned}\ln(Annual\ Southern\&Western\ Region\ Energy) &= \beta_1 \ln(Southern\&Western\ Region\ HDD_{65}) \\ &+ \beta_2 ln(Southern\&Western\ Region\ Residential\ Consumers_{-1}) \\ &+ \beta_3 \ln(\text{Wholesale Rate Real}_{\text{MA}\,3}) + \beta_4 \ln(Residential\ Propane\ Real)\end{aligned}$$

Where:

β_1 = Natural log of Southern & Western Region HDD, Owatonna, MN Basetemp 65,

β_2= Natural log of Southern & Western Region Residential Consumers lagged one-year,

β_3 = Natural log of GRE's Wholesale Rate Real, three-year Moving Average and

β_4 =Natural log of Residential Propane Real).

8.5 Demand Model Development

Description and Assumptions

Monthly coincident peak regression models and forecasts were developed for each forecast region using actual meter data with load control embedded in the data. An assumption is made that our historical load control program will remain consistent in the future, i.e., our historic growth in load control will continue to be the same going forward along with how these load control programs are implemented. All monthly peak forecasts include load control.

Monthly peak regression models were developed for GRE's AR members only within a given forecast region. The Fixed members have entered into a long term power purchase contract and purchase only a fixed amount of their capacity from GRE. The following demand models and forecast are for the AR members only. To calculate the combined AR members and Fixed demand obligation, the fixed amount will be added to the AR member forecast.

Monthly GRE coincident peak demand models and forecast were developed for each forecast region using multiple linear regression techniques in MetrixND©. The aggregation of the three regional GRE coincident peak demand models produces the GRE AR member coincident peak demand forecast.

Demand Regression Model's Structural Form and Coefficients

A monthly coincident peak demand model by forecast region was fit using multiple linear regression techniques with MetrixND©. Weather variables, monthly energy sales, and monthly binaries were the final independent variables used to describe regional coincident peak demand. All resulting models represent the peak demand at the time of GRE's monthly coincident peak. A description of the each of the forecast region's demand model's structural form and explanatory variables are as follows:

Metro Region

$$\begin{aligned}\ln(Monthly\ Metro\ Peak\ Coincident\ Demand) &= \beta_0 + \beta_1 \ln(HotTemp) + \beta_2 \ln(Monthly\ Energy) + \beta_3(January) \\ &+ \beta_4(February) + \beta_5(March) + \beta_6(April) + \beta_7(May) + \beta_8(June) \\ &+ \beta_9(July) + \beta_{10}(August) + \beta_{11}(October) + \beta_{12}(November) \\ &+ \beta_{13}(December)\end{aligned}$$

Where:

β_0 = constant/y-intercept
$\beta_1 \ldots \beta_{13}$ = independent variable coefficients,
HotTemp = Minneapolis/St-Paul Airport HotTemp index at time of coincident peak,
Monthly Energy = Metro region monthly energy ,
January = Binary Variable, if month = January than January = 1, else 0,
February = Binary Variable, if month = February than February = 1, else 0,
March = Binary Variable, if month = March than March = 1, else 0,
April = Binary Variable, if month = April than April = 1, else 0,
May = Binary Variable, if month = May than May = 1, else 0,
June = Binary Variable, if month = June than June = 1, else 0,
July = Binary Variable, if month = July than July = 1, else 0,
August = Binary Variable, if month = August than August = 1, else 0,
October = Binary Variable, if month = October than October = 1, else 0,
November = Binary Variable, if month = November than November = 1, else 0 and
December = Binary Variable, if month = December than December = 1, else 0.

Northern Region

$$
\begin{aligned}
\ln(Monthly\ Northern\ Region\ Peak\ Coincident\ Demand) \\
&= \beta_0 + \beta_1 \ln(HotTemp) + \beta_2 \ln(-1 * ColdTemp) + \beta_3 \ln(Monthly\ Energy) \\
&+ \beta_4(January) + \beta_5(February) + \beta_6(March) + \beta_7(April) + \beta_8(May) \\
&+ \beta_9(June) + \beta_{10}(July) + \beta_{11}(August) + \beta_{12}(October) + \beta_{13}(November) \\
&+ \beta_{14}(December)
\end{aligned}
$$

Where:

β_0 = constant/y-intercept
$\beta_1 \ldots \beta_{14}$=independent variable coefficients,
HotTemp = Hibbing, MN HotTemp index at time of coincident peak,
ColdTemp =Hibbing, MN ColdTemp index at time of coincident peak,
Monthly Energy = Northern region monthly energy,
January = Binary Variable, if month = January than January = 1, else 0,
February = Binary Variable, if month = February than February = 1, else 0,
March = Binary Variable, if month = March than March = 1, else 0,
April = Binary Variable, if month = April than April = 1, else 0,
May = Binary Variable, if month = May than May = 1, else 0,
June = Binary Variable, if month = June than June = 1, else 0,
July = Binary Variable, if month = July than July = 1, else 0,
August = Binary Variable, if month = August than August = 1, else 0,
October = Binary Variable, if month = October than October = 1, else 0,
November = Binary Variable, if month = November than November = 1, else 0 and
December = Binary Variable, if month = December than December = 1, else 0.

Southern & Western Region

$$
\begin{aligned}
\ln(Monthly\ Southern\ \&\ Western\ Region\ Peak\ Coincident\ Demand) \\
&= \beta_0 + \beta_1 \ln(HotTemp) + \beta_2 \ln(-1 * ColdTemp) + \beta_3 \ln(Monthly\ Energy) \\
&+ \beta_4(January) + \beta_5(February) + \beta_6(March) + \beta_7(April) + \beta_8(May) \\
&+ \beta_9(June) + \beta_{10}(July) + \beta_{11}(August) + \beta_{12}(October) + \beta_{13}(November) \\
&+ \beta_{14}(December)
\end{aligned}
$$

Where:

β_0 = constant/y-intercept
$\beta_1 \ldots \beta_{14}$=independent variable coefficients,
HotTemp = Mason City, Iowa HotTemp index at time of coincident peak,
Cold Temp =Mason City, Iowa ColdTemp index at time of coincident peak,
Monthly Energy = Southern & Western region monthly energy,
January = Binary Variable, if month = January than January = 1, else 0,
February = Binary Variable, if month = February than February = 1, else 0,
March = Binary Variable, if month = March than March = 1, else 0,
April = Binary Variable, if month = April than April = 1, else 0,
May = Binary Variable, if month = May than May = 1, else 0,
June = Binary Variable, if month = June than June = 1, else 0,
July = Binary Variable, if month = July than July = 1, else 0,
August = Binary Variable, if month = August than August = 1, else 0,

October = Binary Variable, if month = October than October = 1, else 0,
November = Binary Variable, if month = November than November = 1, else 0 and
December = Binary Variable, if month = December than December = 1, else 0.

8.6 Energy and GRE Coincident Peak Additions and Subtractions

All energy and coincident peak demand adjustments are due to one of the following:

1. A long term power contract to purchase or sell a fixed amount of energy and capacity;
2. A current load that will have a contract expire and GRE will not be renewing it;
3. Transmission and DC Line Losses; or
4. A future load that GRE is currently obligated to serve.

Additions:

The following additions have been made to the IRP forecasts.

- **Fixed member requirements**
  Eight of GRE's 28 members have entered into a long-term power purchase contract and purchase only a fixed amount of their capacity and energy from GRE.
- **Southern Minnesota Electrical Cooperative**
  SMEC was formed by 12 electric distribution cooperatives as the single point of contact for the purchase of electric service territory in Southern Minnesota from Alliant Energy. Five of the 12 distribution cooperatives are AR members of GRE. At the end of 2024, a supply agreement with Alliant Energy will be terminated and the five AR members in SMEC will be required to serve this load. GRE will then be responsible for serving the energy and demand of the new SMEC loads of our five AR members beginning in 2025. We talked with our SMEC members who are also GRE members to forecast the additional energy and demand requirements of those new loads on their systems.
- **DC line losses**
  DC line losses associated with GRE's 400-kV high-voltage direct current (HVDC) transmission line, which transports electricity from GRE's largest generation facility, Coal Creek Station in Underwood, North Dakota, to Minnesota.
- **Transmission losses**
  Transformation losses and transmission losses associated with GRE's 20 AR members and eight Fixed members.

Subtractions

The following subtraction has been made to the IRP forecasts.

- **Elk River Municipal Utilities**
  Currently Elk River Municipal Utilities (ERMU) receives wholesale power from GRE through an "All Requirement" purchase power agreement with Connexus Energy, one of GRE's 28 members. This power purchase agreement expires on September 30, 2018 after which neither GRE nor Connexus Energy will be serving energy and demand requirements for ERMU.

8.7 GRE's Annual Energy and Coincident Peak Demand Requirements

GRE's annual energy requirement increases from 13,041,357 MWh in 2015 to 15,591,718 MWh in 2029 (Figure 8-4 and Table 8-1), a CAGR of 1.3 percent. GRE's five-year CAGR is 0.5 percent; the slight drop in the forecast in 2019 is a result of the termination of the ERMU contract. The 1.3 percent CAGR is lower than the growth experienced during early to late 2000's. GRE believes this is attributed to the slow recovery in the residential consumer class, and customer and utility sponsored efforts in conservation and efficiency.

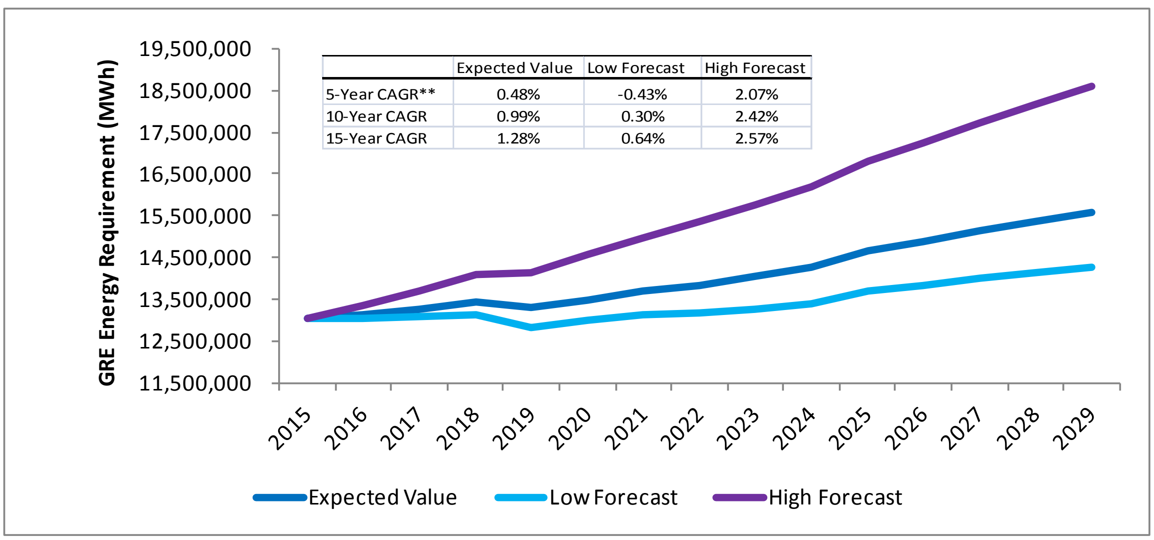

Figure 8-4. Forecast GRE energy requirement from 2015 through 2029.

Table 8-1. GRE energy requirement forecast. Includes all future energy additions, subtractions, DC line losses, and transmission losses.

Year	All Requirement Member Forecast (=)	Elk River Municipal (-)*	DC Line Losses (+)*	Transmission Losses (+)*	Allliant Load Southern Coops Forecasts (+)*	Fixed Member Requirements (+)*	Dakota Spirit Ag (+)*	Energy Requirement Forecast
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2015	9,356,229	0	559,055	537,515	0	2,553,891	34,667	13,041,357
2016	9,439,215	0	560,637	541,894	0	2,561,282	41,600	13,144,629
2017	9,566,910	0	559,055	547,217	0	2,551,863	41,600	13,266,644
2018	9,728,411	0	559,055	554,422	0	2,550,478	41,600	13,433,966
2019	9,883,123	(288,298)	559,055	548,411	0	2,550,478	41,600	13,294,368
2020	10,056,657	(288,298)	560,637	556,220	0	2,550,478	41,600	13,477,294
2021	10,255,236	(288,298)	559,055	565,156	0	2,550,478	41,600	13,683,226
2022	10,402,439	(288,298)	559,055	571,780	0	2,550,478	41,600	13,837,053
2023	10,593,414	(288,298)	559,055	580,374	0	2,550,478	41,600	14,036,623
2024	10,792,093	(288,298)	560,637	589,314	0	2,550,478	41,600	14,245,825
2025	10,998,505	(288,298)	559,055	606,801	182,190	2,550,478	41,600	14,650,331
2026	11,217,028	(288,298)	559,055	616,635	182,190	2,550,478	41,600	14,878,688
2027	11,461,867	(288,298)	559,055	627,653	182,190	2,550,478	41,600	15,134,544
2028	11,671,973	(288,298)	560,637	637,107	182,190	2,550,478	41,600	15,355,688
2029	11,899,353	(288,298)	559,055	647,340	182,190	2,550,478	41,600	15,591,718
* All Forecasts share these components regardless of sensitivities								
**Five-year CAGR is significantly impacted with the loss of Elk River Municipal in 2019.							5-Year CAGR**	**0.48%**
							10-Year CAGR	**0.99%**
							15-Year CAGR	**1.28%**

GRE's annual coincident peak demand requirement increases from 2,452 MWs in 2015 to 2,825 MWs in 2029 (Figure 8-5 and Table 8-2), a CAGR of 1 percent. GRE's five-year coincident peak demand requirement's CAGR is 0.15 percent, the slight drop in the forecast in 2019 is a result of the termination of the Elk River Municipal contract. The 1 percent CAGR is lower than the growth experienced during early to late 2000's.

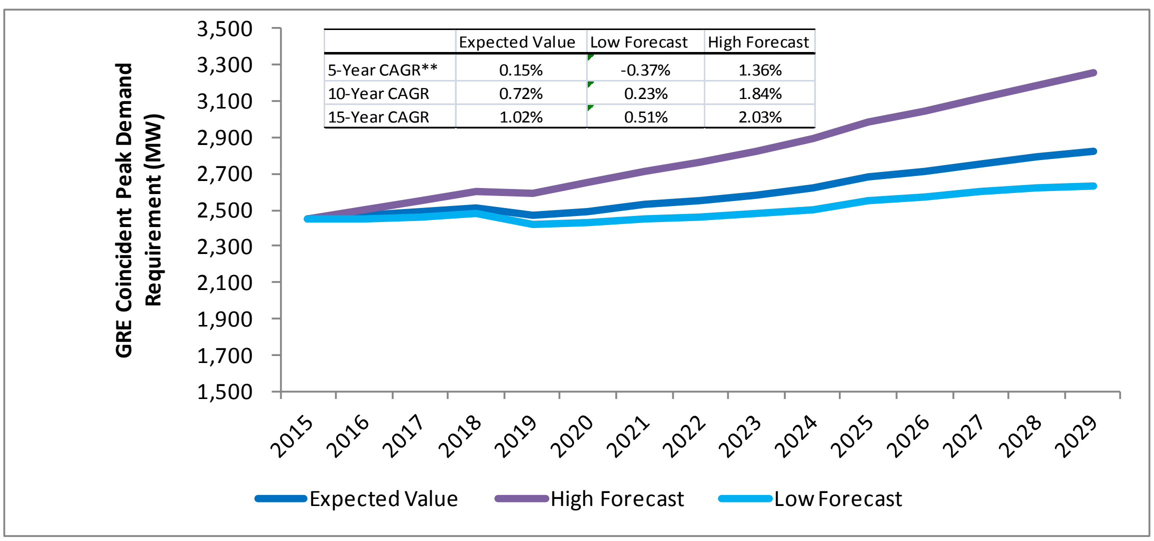

Figure 8-5. Forecast GRE annual coincident peak demand requirement from 2015 through 2029.

Table 8-2. GRE coincident peak demand forecast. Includes all future demand additions, subtractions, DC line losses, and transmission losses.

Year	All Requirement Member Forecast (=)	Elk River Municipal (-)*	DC Line Losses (+)*	Transmission Losses (+)*	Allliant Load Southern Coops Forecasts (+)*	Fixed Member Requirements (+)*	Dakota Spirit Ag (+)*	Coincident Peak Demand Requirement
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
2015	1,769	0	77	102	0	498	5	2,452
2016	1,782	0	77	103	0	498	5	2,466
2017	1,802	0	77	104	0	498	5	2,487
2018	1,828	0	77	105	0	498	5	2,514
2019	1,853	(70)	77	103	0	498	5	2,466
2020	1,880	(70)	77	104	0	498	5	2,495
2021	1,912	(70)	77	106	0	498	5	2,528
2022	1,935	(70)	77	107	0	498	5	2,552
2023	1,965	(70)	77	108	0	498	5	2,584
2024	1,996	(70)	77	109	0	498	5	2,617
2025	2,029	(70)	77	112	27	498	5	2,678
2026	2,063	(70)	77	114	27	498	5	2,714
2027	2,101	(70)	77	115	27	498	5	2,754
2028	2,134	(70)	77	117	27	498	5	2,788
2029	2,169	(70)	77	118	27	498	5	2,825
* All Forecasts share these components regardless of sensitivities								
**Five-year CAGR is significantly impacted with the loss of Elk River Municipal in 2019.							5-Year CAGR**	**0.15%**
							10-Year CAGR	**0.72%**
							15-Year CAGR	**1.02%**

8.8 Energy and GRE Coincident Demand Sensitivities

High and Low Load Growth

Hourly load shapes were created by scaling up or down the base forecast. High and low growth sensitivities were determined by increasing the 15-year compounded annual growth rate of the base forecast by 100 percent and decreasing the 15-year compounded annual growth rate of the base forecast by 50 percent (Table 8-3 and 8-4), respectively.

Increased Conservation and Energy Efficiency

The expected forecast includes embedded conservation and energy efficiency, with the assumption that conservation and energy efficiency will continue in the future at the same rate as they have in the past. We also evaluated increased levels of conservation and energy efficiency, raising them from the inherent 1.5 percent embedded in the base energy forecast to 1.75 percent and 2.0 percent (Table 8-3).

Table 8-3. Annual energy forecast sensitivities for high and low growth, increased conservation and efficiency, customer owned distributed generation and electrical vehicles.

Year	Energy Requirement Forecast (MWh)	High Energy Forecast (MWh)	Low Energy Forecast (MWh)	Medium High Conservation & Electrical Efficiency Forecast (MWh)	High Conservation and Electrical Efficiency Forecast (MWh)	Increased Distributed Generation Forecast (MWh)	Increased Electric Vehicles Forecast (MWh)
2015	13,041,357	13,041,357	13,041,357	13,017,966	12,994,634	13,029,319	13,041,609
2016	13,144,629	13,359,430	13,049,770	13,121,031	13,097,492	13,120,256	13,145,012
2017	13,266,644	13,696,246	13,076,927	13,242,727	13,218,869	13,229,783	13,267,222
2018	13,433,966	14,078,368	13,149,390	13,409,645	13,385,385	13,384,277	13,434,840
2019	13,294,368	14,153,571	12,820,075	13,269,660	13,245,014	13,231,515	13,295,690
2020	13,477,294	14,551,298	13,003,000	13,452,152	13,427,073	13,400,801	13,479,299
2021	13,683,226	14,972,031	13,114,074	13,657,588	13,632,014	13,592,942	13,686,252
2022	13,837,053	15,340,659	13,173,043	13,811,047	13,785,106	13,732,440	13,841,630
2023	14,036,623	15,755,029	13,277,753	14,010,139	13,983,722	13,917,207	14,043,545
2024	14,245,825	16,179,032	13,392,097	14,218,845	14,191,932	14,111,039	14,256,323
2025	14,650,331	16,798,339	13,701,745	14,622,835	14,595,408	14,500,171	14,666,163
2026	14,878,688	17,241,496	13,835,242	14,850,645	14,822,673	14,712,670	14,902,628
2027	15,134,544	17,712,154	13,996,240	15,105,890	15,077,307	14,952,297	15,170,744
2028	15,355,688	18,148,098	14,122,525	15,326,508	15,297,401	15,156,579	15,410,570
2029	15,591,718	18,598,928	14,263,696	15,561,969	15,532,295	15,375,938	15,661,021
5-Year CAGR	0.48%	2.07%	-0.43%	0.48%	0.48%	0.39%	0.48%
10-Year CAGR	0.99%	2.42%	0.30%	0.99%	0.98%	0.89%	0.99%
15-Year CAGR	1.28%	2.57%	0.64%	1.28%	1.28%	1.19%	1.32%

Distributed Energy Resources

In an attempt to identify the impacts of Distributed Energy Resources, or Distributed Generation, in the forecast period, we included a sensitivity that assumed our members would develop solar energy resources of 1.5 percent of their annual energy requirements.

Hourly load shapes were developed to represent an increase in customer-owned PV systems that reduce GRE retail sales by 1.5 percent in 2029. Size and number of systems were considered across the residential, small commercial, and large commercial customer classes. Base hourly load shapes for the residential, small commercial, and large commercial systems were based off of hourly PV data in Minneapolis, Minnesota for an average metrological year. Table 8-3 and Table 8-4 reflect the impact of this sensitivity on the energy and demand forecasts.

Electric Vehicles

Hourly load shapes were developed to reflect 5 percent saturation in electric vehicles in GRE's metro area by 2029. Charging types and time-of-use charging programs were considered in the modeling effort. Table 8-3 and Table 8-4 reflect the impact of this sensitivity on the energy and demand forecasts.

Table 8-4. Annual coincidental peak demand forecast sensitivities for high and low, customer owned distributed generation and electrical vehicles.

Year	Coincident Peak Demand Requirement Forecast	High Demand Forecast	Low Demand Forecast	Increased Distributed Generation Forecast	Increased Electric Vehicles Forecast
	(MW)	(MW)	(MW)	(MW)	(MW)
2015	2,452	2,452	2,452	2,446	2,452
2016	2,466	2,496	2,453	2,454	2,466
2017	2,487	2,548	2,462	2,470	2,488
2018	2,514	2,605	2,476	2,491	2,515
2019	2,466	2,588	2,416	2,438	2,468
2020	2,495	2,647	2,432	2,460	2,497
2021	2,528	2,710	2,452	2,487	2,531
2022	2,552	2,765	2,464	2,505	2,556
2023	2,584	2,827	2,483	2,530	2,589
2024	2,617	2,890	2,503	2,555	2,623
2025	2,678	2,982	2,552	2,610	2,687
2026	2,714	3,048	2,575	2,639	2,726
2027	2,754	3,119	2,602	2,671	2,769
2028	2,788	3,183	2,624	2,698	2,807
2029	2,825	3,250	2,632	2,727	2,846
5-Year CAGR	0.15%	1.36%	-0.37%	-0.09%	0.16%
10-Year CAGR	0.72%	1.84%	0.23%	0.49%	0.75%
15-Year CAGR	1.02%	2.03%	0.51%	0.78%	1.07%

8.9 MISO Module E Resource Adequacy Obligation

GRE's 2014 IRP and 2012 IRP have been based on demand forecasts that projected our coincident peak summer demand requirement at a system level and energy forecasts that project our aggregate system energy requirement. Resource planning around MISO's coincident peak was not considered prior to GRE's 2012 IRP.

With FERC's acceptance of the MISO Resource Adequacy Proposal in FERC Docket No. ER-11-4081-000, Section 69A.1, a market participant is now required to forecast resource adequacy based on the utility's peak coincident with MISO's entire system peak: In MISO's tariff section 69A.1.1a,

> "The demand forecast shall include the annual Coincident Peak Demand within each LBA area in the Transmission Provider Region for the upcoming Planning Year."

These LBA demand forecasts must be an estimate of the amount of demand GRE contributes to the MISO summer peak.

GRE's 2014 IRP was developed using a planning requirement that is based on MISO's coincident peak. However, we also conducted sensitivities that looked at resource needs based solely on our own system peak. The results showed little difference in the expansion plans since new resources are not needed until late in the forecast period.

Please see Midcontinent Independent System Operator, Inc – Clarifying Responsive Comments submitted in Otter Tail Power Company's 2013 Integrated Resource Plan filing, Docket Nos. E017/RP-13-961 for a detailed description of the history, methodologies, and calculations behind MISO's Module E Forecast and planning reserve margin.

GRE's MISO Module E Forecast Development

GRE's MISO Module E forecast is developed by the aggregation of seven independent CPnode forecasts. Based on forecast guidelines provided by MISO, seven independent non-coincident peak forecast are developed for each of the CPnodes that are within GRE's service region. Using guidelines provided by MISO, a causal approach is used to develop a coincidence factor between each of the seven CPnodes' summer non-coincident peaks and MISO's summer coincident peak. This CPnode specific coincident factor is applied to each CPnode's non-coincident peak to determine the CPnode's contribution to MISO's summer coincident peak. The summation of each CPnode's contribution to MISO's summer coincident peak results in GRE's MISO Module E forecast. This forecast is developed completely independent of the forecast used in the 2014 IRP.

GRE's 2014 IRP Forecast Development

GRE's 2014 IRP forecasts are developed around both GRE's peak summer demand requirement and total system energy requirement. To make this forecast compatible to a MISO Module E forecast, a coincidence factor was developed that explained the relationship between GRE's peak summer demand requirement and the MISO Coincident Peak summer demand. A detailed summary of methodology used to develop this coincidence factor can be found in Appendix H: GRE MISO Coincident Peak Diversity Study.

Coincident Factor Development

A peak load diversity study between the time of the GRE's summer coincident peak demand requirement and MISO's coincident peak was performed using three methods that utilized observed summer load diversity from 2005 through 2012. Currently MISO includes the summer months of June, July, August, and September as the months that MISO could experience its summer coincident peak.

Utilizing a series of paired T-Tests to test whether or not one month's average diversity factor was statistically different from another month's average diversity factor resulted in no statistical difference in any of the months compared.

A comparison of each month's average diversity factor's 95 percent confidence interval indicates each of the months has an overlapping confidence interval. This test indicates that based on a sample size of eight from years 2005 through 2012, there is no significant difference in the average diversity factor for the months of June, July, August, and September (Figure 8-6).

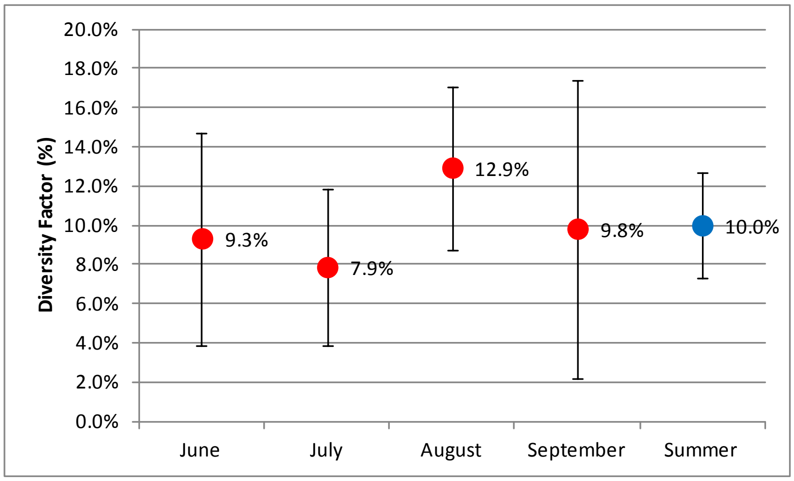

Figure 8-6. Upper and lower 95% confidence interval for summer months 2005-2012, 10% +/- 2.7%.

Using the three different methods for estimating load diversity between GRE's coincident peak and MISO's coincident peak, a wide range of statistically credible diversities was estimated and probability of occurrence (Table 8-5). Based on consensus between the estimated diversity factor and probability of occurrence between the MISO – Causal Approach and the Historic Average Summer Diversity (Table 8-5), a diversity factor of 10 percent has been used to explain the diversity between GRE coincident peak and MISO's coincident peak.

Table 8-5. Load diversity decision matrix for simulating different levels of market, system load reliability, and probability of occurrence risk.

Diversity Factor Method	Estimated Diversity Factor	Probability of Occurrence Rank
Lower 95% Confidence Interval	7.20%	1(0.15625)
Upper 95% Confidence Interval	12.70%	3(0.125)
Average	**10%**	**4(0.0625)**
Median	7.90%	1(0.15625)
Minimum	0%	6(0.03125)
MISO - Causal Approach	**10%**	**4(0.0625)**

8.10 Demand Response

GRE's demand response (DR) programs intentionally change end-use members' electric usage patterns from their normal consumption patterns to 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, to shift the electricity use to times when wholesale market prices are at their lowest, normally the nighttime hours. By actively engaging tens of thousands of our members' end-use customers, GRE is able to reduce electric price volatility and the need for additional generation capacity, while enhancing system reliability and members' value.

Demand Response History through Present

GRE has been investing in demand response 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 which shift member loads. Time clocks were replaced long ago by direct load control technologies which use VHF frequencies 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 members by accompanying their Advanced Metering Infrastructure (AMI) deployment.

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

Historically demand response activities were utilized to reduce the coincident peak for the utility. That method of controlling resources is typically referred to as peak shaving. Peak shaving still plays a significant role in the overall value of demand response. However, moving forward we will be focusing more of our demand response efforts on controlling for energy prices and to participate in ancillary services markets.

GRE includes the impacts of our DR program in the forecast process. The forecast assumptions used in estimating future DR impacts are:

- Our proactive demand response program will continue in the future;
- We will operate our demand response program in the future the same way that we have in the past;
- We forecast a metered coincident peak and not an estimated uncontrolled coincident peak; and
- We will continue to account for demand response savings as they are reflected in historical data, resulting in monthly peak demand forecast.

Methodology

In order to fully take advantage of the benefits of the demand response resource that GRE has invested in, we and our members typically control loads on summer peak days from 1 p.m. to 10 p.m. (Figure 8-7 C, D, and E). This large window of control is necessary as it captures multiple value streams for the utilities. The MISO wholesale energy market prices typically peak between 1 p.m. and 4 p.m. in our area. Controlling loads between these hours provides an opportunity to lower purchased energy cost by moving the time the energy is purchased to later in the day, when it is usually less expensive.

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 resource adequacy capacity requirements. This was the initial incentive that drove our investment in demand response. Control after 7 p.m. is done to avoid setting a new system peak when the loads being controlled are restored. If we were to release control of the loads at 7:01 p.m., a new system peak would occur from the surge of consumption from all the controlled devices consuming 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 (Figure 8-7 A, C, D, and E).

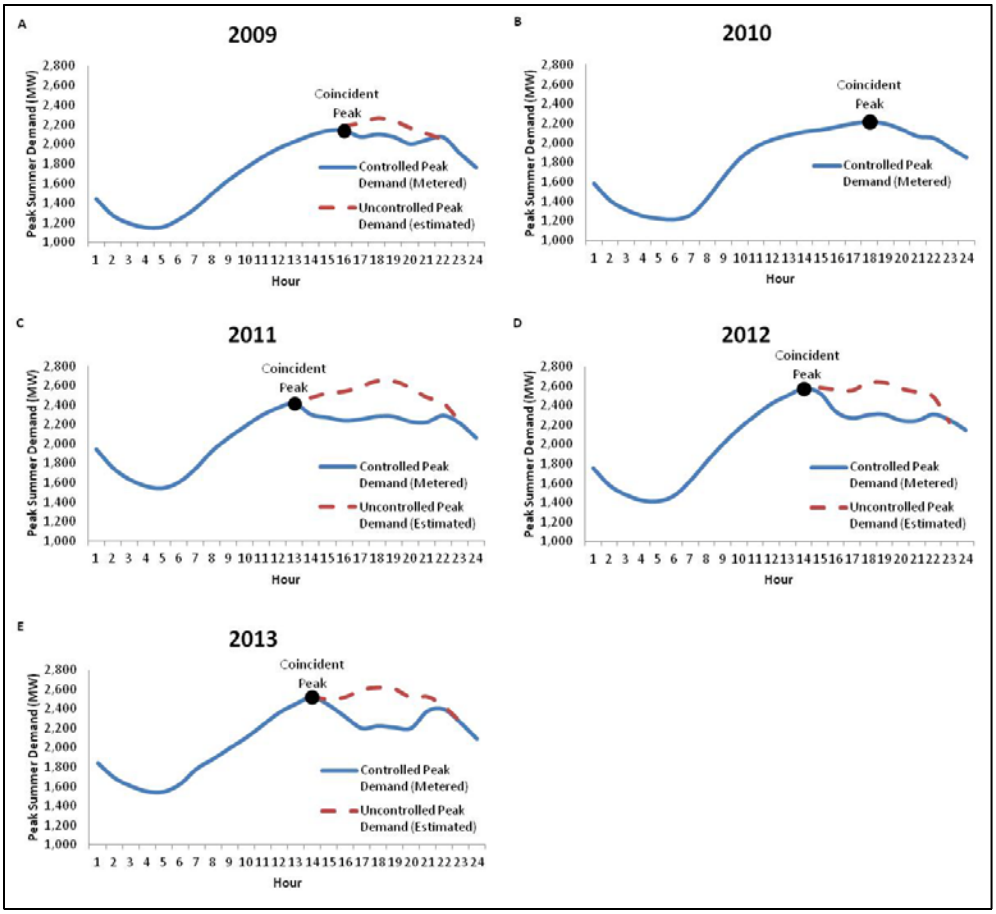

Figure 8-7. Historic controlled and uncontrolled hourly load shapes on the day of GRE's coincident peaks.

In the past 10 years, our demand response capabilities have grown in four core areas:

- Peak shave water heating (PSW),
- Irrigation,
- Cycled air conditioning, and
- Commercial and industrial use (C&I) (Figure 8-8).

The overall maximum control amount capabilities has increased from around 300 MWs to almost 400 MWs, a 10-year compounded annual growth rate of 2.8 percent (Figure 8-9).

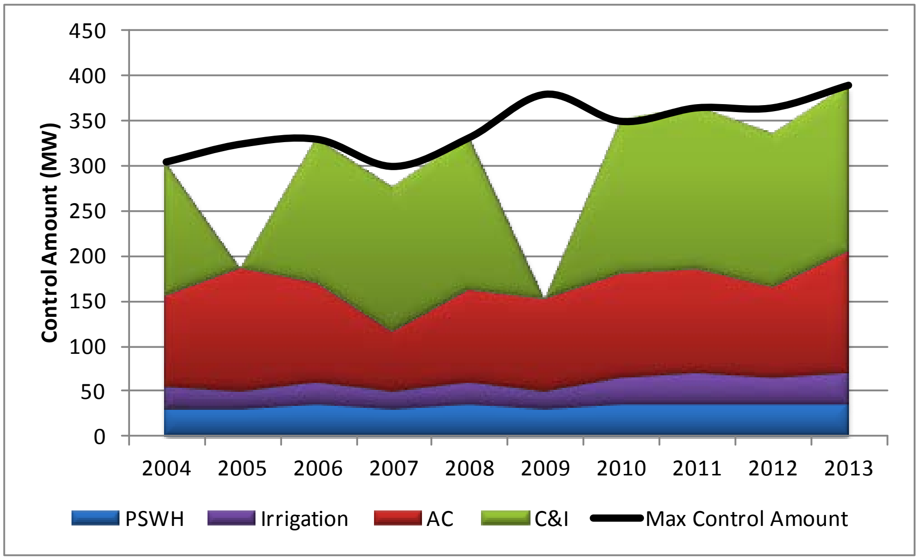

Figure 8-8. Historic demand response capabilities by program.

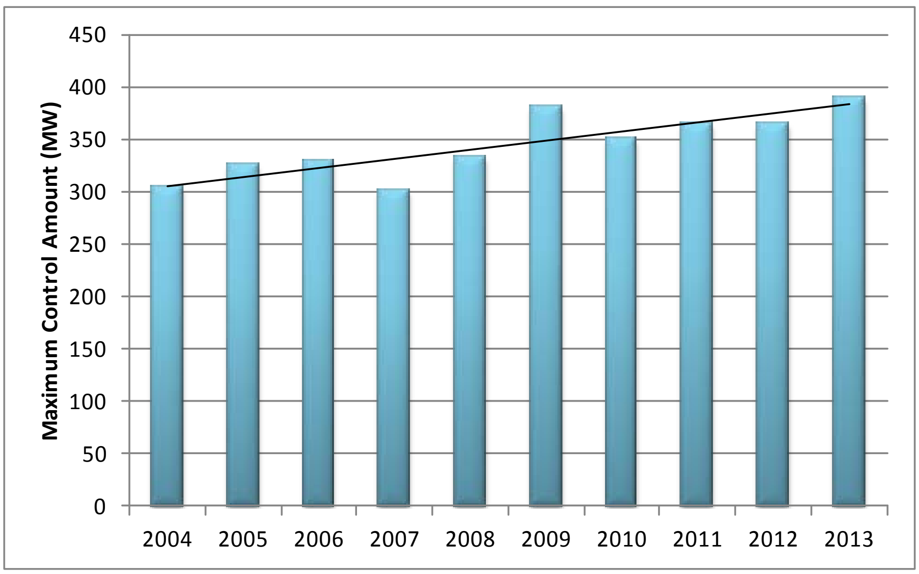

Figure 8-9. GRE's historic growth of total demand response. Maximum control amount represents GRE's capability in peak load reduction.

Demand Response Terminology

Coincident Peak verse Uncontrolled Peak

GRE forecasts the monthly coincident peak as opposed to the uncontrolled coincident peak. 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 demand response program called, e.g., power shave water heating, irrigation, cycled air conditioning.

Embedded Demand Response Savings

The total embedded demand response 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 blue found in Figure 8-10. The amount of coincident peak demand savings due to demand response can be calculated by subtracting the metered coincident peak (the orange dot) from the estimated uncontrolled coincident peak (the red dot), as shown in Figure 8-10. The total amount of energy savings from demand response on a given day can be calculated by summing the difference between the metered demand (the green line) and estimated uncontrolled demand (the blue dashed line) in Figure 8-10.

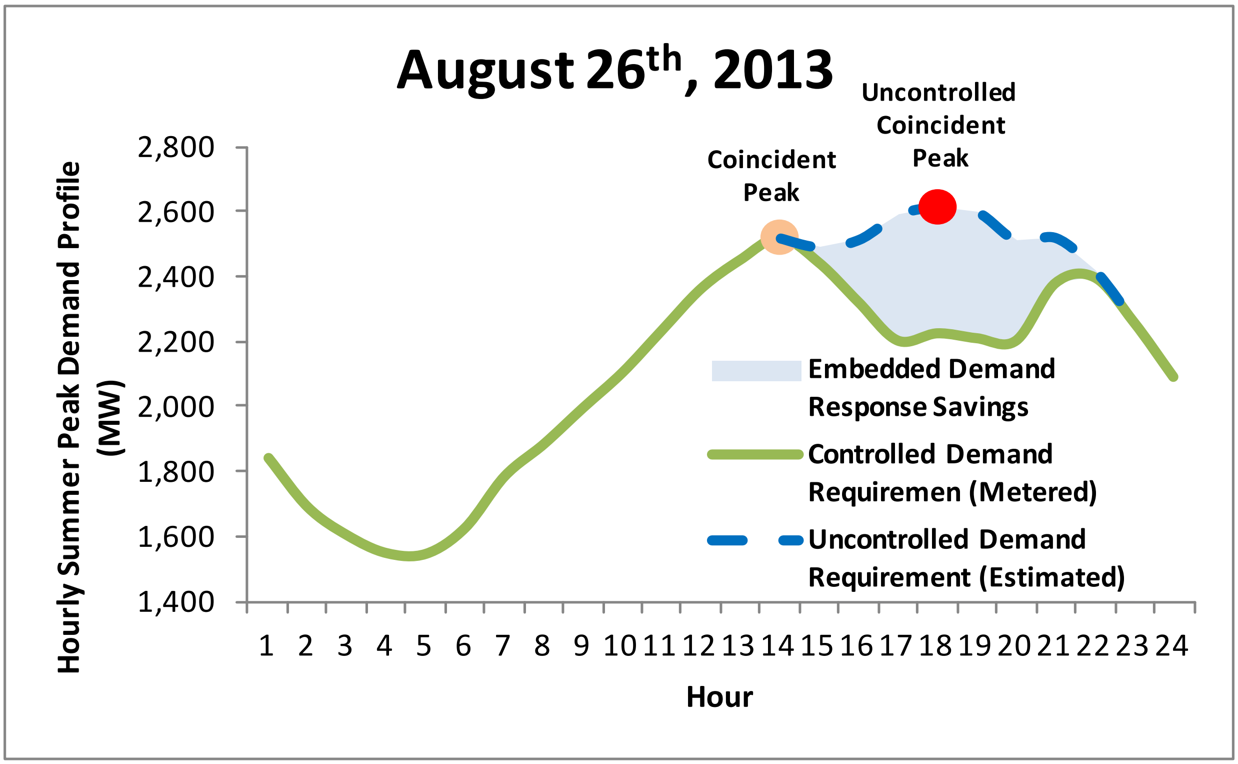

Figure 8-10. Controlled and Uncontrolled GRE Coincident Peak and associated demand response terminology.

Example Demand Response Savings Calculation

On August 26, 2013, GRE's load control program was called upon between the hours of 3 p.m. and 10 p.m. (Figure 8-10 and Table 8-6). The total amount of coincident peak reduction was 96 MWs (2616 MW – 2521 MW) and 1888 MWh of energy savings (Table 8-6).

Table 8-6. Controlled and Uncontrolled GRE coincident peak with estimates of control amounts, demand savings, and energy savings.

Date	Hour	Temp	Metered Demand	Estimate Uncontrolled Demand	Estimate of Load Control
8/26/2013	1	81	1842		0
8/26/2013	2	80	1690		0
8/26/2013	3	78	1604		0
8/26/2013	4	76	1549		0
8/26/2013	5	75	1547		0
8/26/2013	6	74	1627		0
8/26/2013	7	73	1786		0
8/26/2013	8	75	1885		0
8/26/2013	9	81	1997		0
8/26/2013	10	82	2106		0
8/26/2013	11	86	2236		0
8/26/2013	12	89	2364		0
8/26/2013	13	92	2453		0
8/26/2013	14	92	2521		0
8/26/2013	15	93	2443	2493	50
8/26/2013	16	93	2322	2517	195
8/26/2013	17	93	2204	2594	390
8/26/2013	18	91	2226	2616	390
8/26/2013	19	88	2211	2601	390
8/26/2013	20	87	2204	2514	310
8/26/2013	21	84	2381	2522	141
8/26/2013	22	82	2399	2421	22
8/26/2013	23	80	2260		0
8/26/2013	24	81	2092		0
			Demand Response Savings		1888 MWh

Demand Response Coincident Peak Reduction

Diversity Factor

The diversity between the metered coincident peak demand and the estimated uncontrolled peak demand can be used to develop a historic diversity factor to calculate the amount of peak demand reduction projected in the forecast due to demand response. To utilize the methodology, the assumption is made that the demand response program will continue to be implemented the same way in the future as it has been implemented in the past.

Using the demand response methodology described in the previous section, a calculated diversity between the metered coincident summer peak and the uncontrolled coincident peak is 5 percent with an upper and lower confidence interval of 9.6 percent and 0.4 percent. Based on this diversity factor, the estimated uncontrolled coincident summer peak is on average 5 percent higher than the metered summer coincident peak. The expected amount of coincident summer peak demand reduction due to demand response is illustrated in Figure 8-11. The dark blue line is the expected amount of summer peak demand reduction due to demand response and the area shaded in blue represents the 95 percent confidence interval. In 2015, there is an expected 123 MW reduction, however; depending on weather, the load control amounts could range from as little as zero megawatts to 236 MWs. Sources of variability in demand response savings are due to yearly changes in weather, humidity and timing of demand response with weather variation providing the greatest amount of variability.

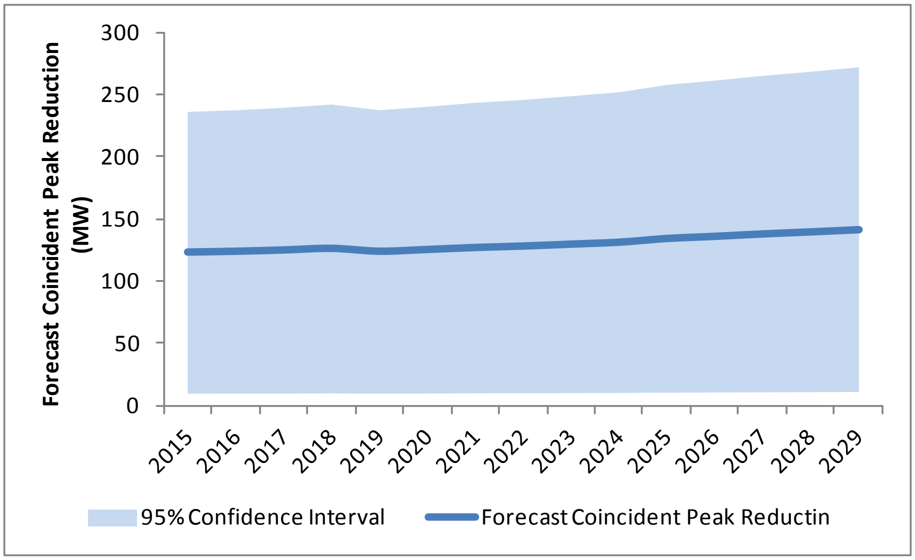

Figure 8-11. Forecast amounts of demand response savings at the time of GRE's coincident peak.

Forecast With and Without Demand Response

Using the diversity factor of the meter coincident peak and the estimated uncontrolled peak, an estimate is made of what the uncontrolled coincident peak would have been in any given year (Figure 8-12). Expected coincident peak load reduction due to demand response across the 15-year forecast period ranges from 122 MWs to 140 MWs, or a 15-year compounded average growth rate of 1 percent (Table 8-7).

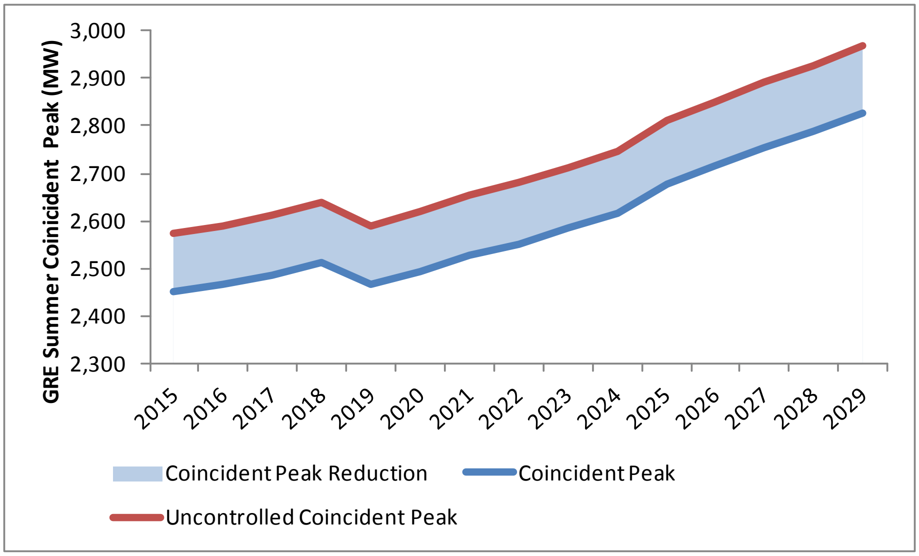

Figure 8-12. Controlled and uncontrolled coincident peak demand forecasts.

Table 8-7. Amounts of demand response savings and associated 95% confidence intervals.

Year	Coincident Peak	Demand Response Savings		
		Average	LCL95	UCL95
	------------------------MW------------------------			
2015	2,452	122	2,444	2,670
2016	2,466	123	2,461	2,688
2017	2,487	123	2,475	2,703
2018	2,514	124	2,496	2,727
2019	2,466	126	2,523	2,756
2020	2,495	123	2,476	2,704
2021	2,528	125	2,504	2,736
2022	2,552	127	2,538	2,772
2023	2,584	128	2,562	2,798
2024	2,617	129	2,593	2,833
2025	2,678	131	2,626	2,869
2026	2,714	134	2,688	2,936
2027	2,754	136	2,724	2,976
2028	2,788	138	2,764	3,020
2029	2,825	140	2,799	3,057

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9. EXPANSION PLAN ANALYSIS AND RESULTS

9.1 Cases and expansion plans

GRE evaluated 32 cases with various sensitivities as a way to assess outcomes for different future scenarios. The assumptions and sensitivities used in the modeling were externality costs, regulatory costs, energy and demand growth, new resource costs, market prices, market interactions, coal prices, natural gas prices, planning reserve margins, MISO diversity factor, Renewable Portfolio Standards, energy efficiency and conservation levels, owned coal-fired generation retirements and/or the termination of purchase obligations from coal-fired units, customer-owned distributed generation levels, and electric vehicles penetration.

A case matrix was developed to reflect the individual cases and their primary sensitivities, and is shown in Table 9-1. All references to "retirements" in the tables and figures below are intended to mean either the termination of purchase obligations from coal-fired units or the retirement of owned coal-fired units, as applicable.

Table 9-1. Modeling case numbers and key sensitivities.

Case Description	Case Number
Medium Prices/Growth & NO Externalities & No Retirements	1
Medium Prices/Growth & NO Externalities & Retirements	2
Medium Prices/Growth & Low Externalities & Retirements	3
Medium Prices/Growth & Medium Externalities (Base Case) & Retirements	4
Medium Prices/Growth & High Externalities & Retirements	5
Medium Prices/Growth & NO Externalities & Retirements High Hydro Costs	6
Medium Prices/Growth & Medium Externalities & Retirements High Hydro Costs	7
Medium Prices/Growth & NO Externalities & Retirements & Low Soloar Costs	8
Medium Prices/Growth & Medium Externalities & Retirements & Low Solar Costs	9
Low Prices/Growth & Med. Gas Fired Gen. & No Externalities	10
Low Prices/Growth & Med Gas Fired Gen. & Med Externalities	11
High Prices/Growth & High Gas Fired Gen. & No Externalities	12
High Prices/Growth & High Gas Fired Gen. & Med Externalities	13
Medium Prices/Growth & Expected Wind Costs & RPS Not Forced & No Externalities	14
Medium Prices/Growth & Expected Wind Costs & RPS Not Forced & Med Externalities	15
Medium Prices/Growth & low Wind & RPS Not Forced & Med Externalities & High Gas Fire Gen.	16
Medium Prices/Growth & Expected Wind Costs & RPS Not Forced & No Externalities GRE Coin	17
Medium Prices/Growth & Expected Wind Costs & RPS Not Forced & Med Externalities GRE Coin	18
Medium Prices/Growth & NO Externalities & without Market & MISO Coin	19
Medium Prices/Growth & Low Externalities & without Market & MISO Coin	20
Medium Prices/Growth & Medium Externalities & without Market & MISO Coin	21
Medium Prices/Growth & High Externalities & without Market & MISO Coin	22
Medium Prices/Growth & NO Externalities & without Market & GRE Coin	23
Medium Prices/Growth & Low Externalities & without Market & GRE Coin	24
Medium Prices/Growth & Medium Externalities & without Market & GRE Coin	25
Medium Prices/Growth & High Externalities & without Market & GRE Coin	26
High Prices/Growth & expected Wind & without Market & RPS 40% & Med Externalities & High DSM, EE, Con & High Distributed Gen & High PHEV Saturation	27
High EE/Cons No Extranalities & Retirements & Med Growth	28
High PHEV No Extranalities & Retirements & Med Growth	29
High DG (Customer Owned) No Extranalities & Retirements & Med Growth	30
High (EE/Cons, PHEV, DG) No Extranalities & Retirements & Med Growth	31
50/75 Renewable & Energy Efficiency	32

Appendix F: Model Sensitivities Matrix shows the sensitivities and combinations of sensitivities that are associated with each case.

Once the individual cases were run, the cases were then grouped according to what the model selected for generation additions and subtractions across each of the cases. Expansion plans were identified by combining the cases that resulted in similar resource additions and/or subtractions over the 15 year forecast period. Based on the 32 cases considered, 12 different expansion plans were identified and labeled A through L, as shown in Table 9-2.

The Reference Case

We identified Case 4 as the reference case, which includes Commission approved medium externalities and regulatory costs, expected load growth and market prices, expected costs for new solar, wind and natural gas generation, meeting Minnesota's RES, meeting conservation and energy efficiency goals, and allowing coal generation retirement and coal unit purchase obligation termination. Case 4, 7, and 9 resulted in Expansion Plan H. The average PVRR for all cases that result in Expansion Plan H is $8.9 billion.

The Preferred Plan

GRE's Preferred Plan was identified as Expansion Plan E and evaluated with medium externality and regulatory costs in Case 21 and 25. The average PVRR for Case 21 and 25 is $9.2 billion. The average PVRR for all 14 cases that resulted in the Preferred Plan is $7.6 billion. Externality and regulatory costs were included in 17 of the 32 total cases. Five of the 14 cases resulted in the Preferred Plan included externalities and regulatory costs.

Table 9-2. Description of the assumptions and sensitivities among the 12 expansion plans.

Expansion Plan	Predominant Common Assumption(s) & Sensitivity(s)	Average PVRR (Billion $)
A	Low LMP Price & Low Energy & Demand Growth & Retirements & Coal Contract Termination	$6.4
B	50/75 Renewable & Energy Efficiency & Retirements & Coal Contract Termination	$7.1
C	No Generation Retirements and Coal Contract Terminations Allowed	$7.2
D	RPS Not Forced & Retirements & Coal Contract Termination	$7.6
E	Medium Prices & Medium Energy and Demand Growth & Retirements & Coal Contract Termination	$7.6
F	Low LMP Prices & Low Energy and Demand Growth & Low Externalities & Retirements & Coal Contract Termination	$8.1
G	Medium LMP Prices & Medium Energy and Demand Growth & RPS Not Forced & Retirements & Coal Contract Termination	$8.9
H	Medium LMP Prices & Medium Energy and Demand Growth & Medium Externalities & Retirements & Coal Contract Termination	$8.9
I	High LMP Prices & High Energy and Demand Growth & Retirements & Coal Contract Termination	$9.9
J	Medium LMP Prices & High Externalities & Retirements & Coal Contract Termination	$9.9
K	Medium LMP Prices & Medium Energy and Demand Growth & High Externalities & No Market Interaction & Retirements & Coal Contract Termination	$10.2
L	High LMP Prices & High Energy and Demand Growth & No Market Interaction & Medium Externalities & Increased Electric Vehicles & Increased Customer Owned Solar & Increased Electrical Efficiency and Conservation & Retirements & Coal Contract Termination	$11.4

Table 9-3 reflects the generation additions and subtractions in each expansion plan.

Table 9-3. Generation resource additions and subtractions by expansion plan.

	Additions (MW)				Subtractions (MW)			
Expansion Plan	Coal	Gas	Renewable	Lg & Small Hydro	Coal	Gas	Renewable	Lg & Small Hydro
A	0	0	300	200	-119	0	0	0
B	0	0	600	0	-119	0	0	0
C	0	0	600	200	0	0	0	0
D	0	0	0	200	-119	0	0	0
E	0	0	600	200	-119	0	0	0
F	0	400	300	200	-854	0	0	0
G	0	0	0	200	-303	0	0	0
H	0	0	0	200	-303	0	0	0
I	0	0	700	200	-119	0	0	0
J	0	800	600	200	-1412	0	0	0
K	0	1200	600	200	-1412	0	0	0
L	0	0	1400	200	-119	0	0	0

The 12 expansion plans were then evaluated to balance the Minnesota Rules resource plan Factors to Consider; reliability, cost, environmental impacts, and risk. In addition, we evaluated each expansion plan on meeting our Triple Bottom Line of reliability, cost and environmental stewardship.

9.2 Cost Comparison

The Present Value of Revenue Requirements (PVRR) is a method used to evaluate the cost differences across each of the cases and expansion plans. A lower PVRR means the plan meets the energy and capacity needed for our members at a lower cost than higher PVRR expansion plans.

In comparing the PVRR across all individual cases, the range of PVRR was between $6.4 billion to $11.4 billion (Figure 9-1). The lowest PVRRs are associated with those cases that do not include externalities or regulatory costs. The cases with the highest PVRRs result from those cases where medium and high externalities and regulatory costs are combined with medium and high market prices and medium and high load growth.

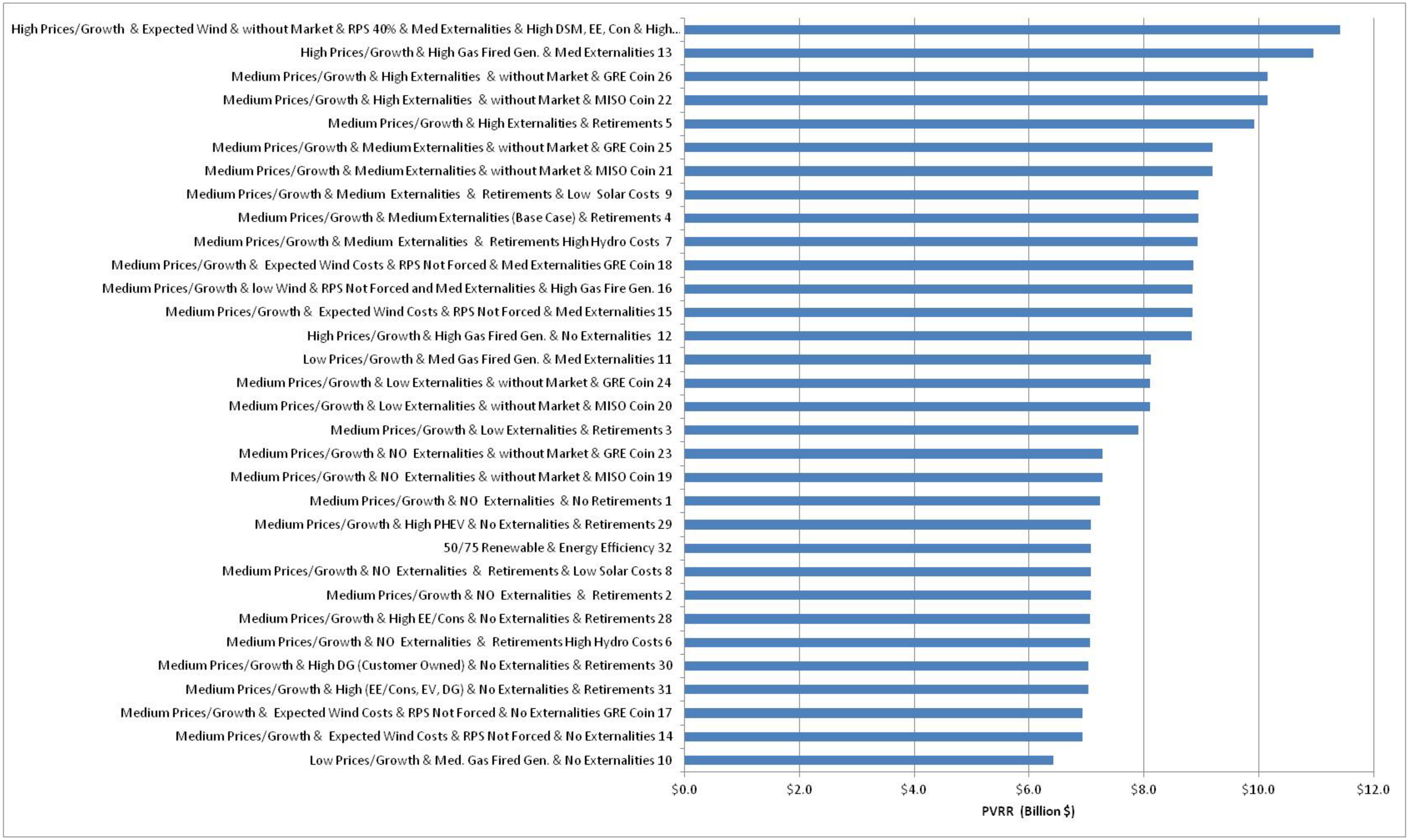

Figure 9-1. PVRR comparison among the 32 individual cases.

Figure 9-2 provides a breakdown of each of the 12 expansion plans and the individual cases that resulted in each expansion plan. As externality costs increase, the average PVRR of the expansion plan increases.

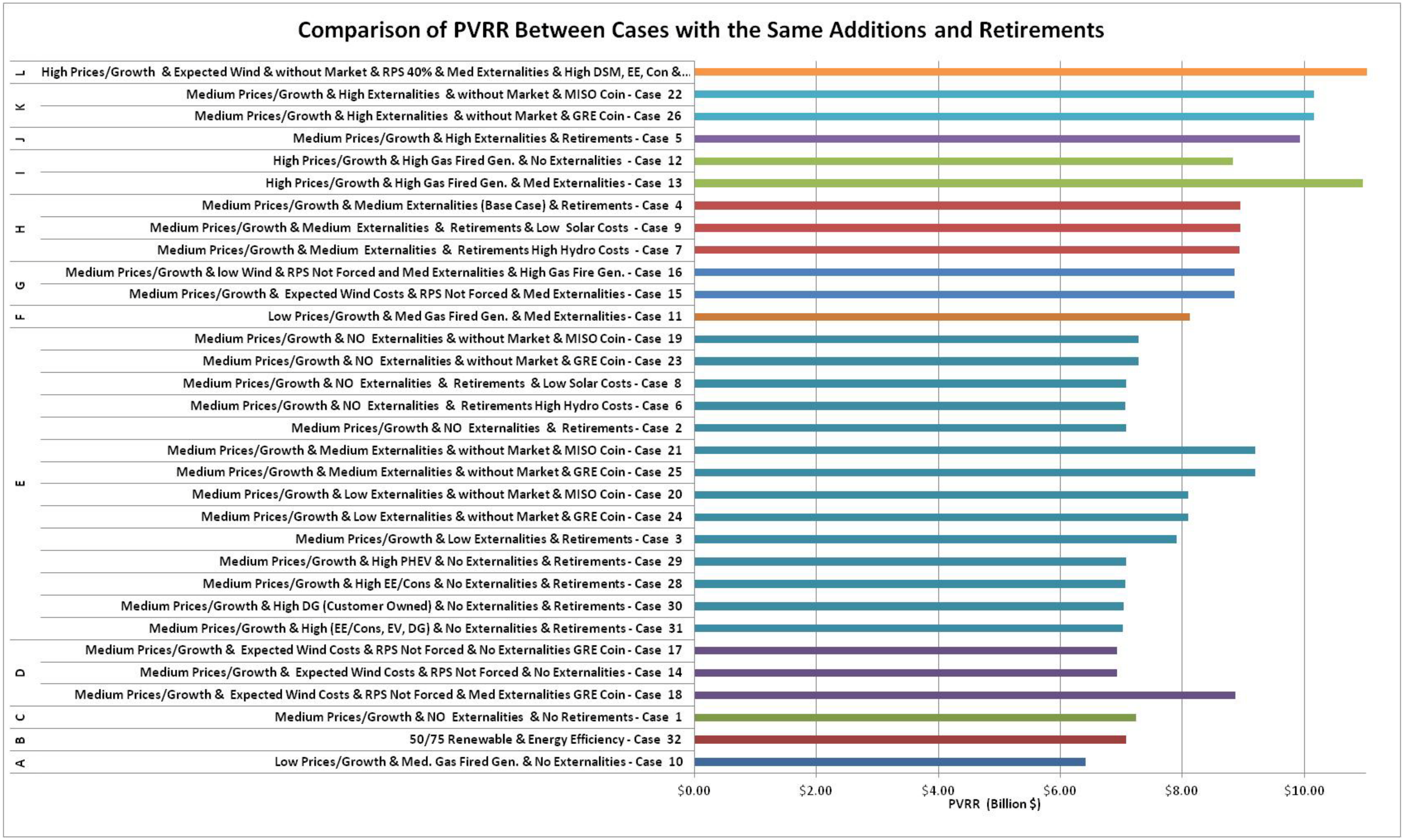

Figure 9-2. Comparison of PVRR between cases with the same Expansion Plan.

Expansion Plan E reflects the largest number of cases, 15 out of the 32, showing the greatest amount of variability in assumption's and sensitivities (Figure 9-2). This expansion plan reflects the sensitivities of with and without externalities, with and without market interaction, planning to GRE's coincident peak and MISO's coincident peak, and different levels of new resource addition costs.

The PVRR associated with Expansion Plan E was among the lowest of all 12 Expansion Plans. Expansion Plans A, B, C and D have lower to slightly lower PVRRs. However, each of these plans contains assumptions that are not expected to be realized within the forecast period. Expansion Plan D does not comply with Minnesota's Renewable Energy Standard. Expansion Plan C does not allow coal generation plant retirements or the termination of purchase obligations from coal units. Expansion Plan B results from a case where no new hydro is allowed as a resource option. Expansion Plan B has a higher PVRR than Expansion Plan E.

Expansion Plan A contains assumptions of low market energy prices and low energy and demand growth. GRE does not consider low market prices and low energy and demand growth as a likely future outcome.

9.3 Reliability Assessment

Coal Retirements

GRE's owned coal fired generation units are economic and meet all environmental regulatory requirements. These units are used to meet our MISO Module E Resource Adequacy requirements and lower the amount of net energy that we purchase from the market.

Our largest generation resource, Coal Creek Station, is a mine-mouth coal plant. The availability of on-site fuel adds to reliability of the facility and minimizes risks associated with rail coal delivery, which has been an issue affecting a number of other coal facilities in the Midwest.

These baseload units are efficient and reliable and add to the reliability of the MISO market. We note that our baseload facilities were in full operation during the 2013/2014 winter, including the Polar Vortex cold weather events. These baseload facilities were running and available during that time of high load, large swings in energy prices, and the fuel and price uncertainty of propane and natural gas.

Coal unit retirements and purchase obligation terminations among the 12 Expansion Plans differ depending on the level of externalities applied to the coal units and coal unit purchase contracts. As externality prices increase, the number of coal unit retirements and purchase obligation terminations increase.

In those cases that allow coal unit retirements and the termination of the obligation to purchase coal from units, only the Genoa 3 purchase obligation is removed when real costs are considered. In cases where externality or carbon regulation costs are included, owned coal generation retirements occur. As externality costs increase, more owned coal generation is retired. In a series of cases without any energy market interaction, only the Genoa 3 contract is terminated until the highest level of externality costs are applied. This suggests that as externality costs increase and coal plants retire, a portfolio like ours requires a greater reliance on the energy market. In the sensitivities without market interaction and with medium externalities and regulatory costs, all owned coal generation is retained to serve load. Only the Genoa 3 purchase obligation is terminated.

The only Expansion Plan that did not result in termination of the obligation to purchase from Genoa 3 was Expansion Plan C, which did not allow any retirements or purchase obligation terminations to be selected, as seen in Table 9-4.

In Expansion Plan E, Genoa 3 was selected by the model to be terminated. This Expansion Plan reflects that GRE will maintain its cost-effective coal units, remove the Genoa 3 contract from our portfolio, and maintain reliability by preserving capacity that is needed to comply with GRE's resource adequacy requirements. Expansion plan E reflects modeling with no and medium-level externality and regulatory costs. This expansion plan is flexible by working with or without market interaction and planning to MISO's peak or our own system peak.

Table 9-4. Comparison of coal retirement/removal and coal contract termination frequency by Expansion Plan.

	Retirement Frequency				
Expansion Plan	Genoa 3	Spiritwood	Stanton Station	Coal Creek - Unit 1	Coal Creek Unit - 2
A	1	0	0	0	0
B	1	0	0	0	0
C	0	0	0	0	0
D	3	0	0	0	0
E	14	0	0	0	0
F	1	0	1	1	0
G	2	0	2	0	0
H	3	0	3	0	0
I	2	0	0	0	0
J	1	0	1	1	1
K	2	0	2	2	2
L	1	0	0	0	0
Number of Times Retired	31	0	9	4	3
% of Times Retired	97%	0%	28%	13%	9%

Coal Energy

With the exception of Expansion Plan C, which did not allow coal retirements or the termination of purchase obligations to be selected, all Expansion Plans show a reduction in coal generation. The total range of reduced coal capacity was negative 11.4 percent to negative 77 percent, which is illustrated in Figure 9-3. As externality prices increase, the amount of energy produced by coal decreases.

The Expansion Plans with the largest reduction in coal energy were those where market interaction is allowed, thereby requiring greater reliance on the market for energy. With the elimination of base load coal generation, natural gas generation increases.

The 14 individual cases in Expansion Plan E show an average reduction in energy coal generation of 16 percent by 2029. This reduction is primarily due to the termination of the Genoa 3 contract. Within Expansion Plan E, there is some increase in energy from natural gas generation due to greater dispatch of our existing peaking plants. No natural gas generation resource additions were selected in Expansion Plan E. Of the fifteen cases that were considered in Expansion Plan E, energy by renewable and hydro remains relatively consistent.

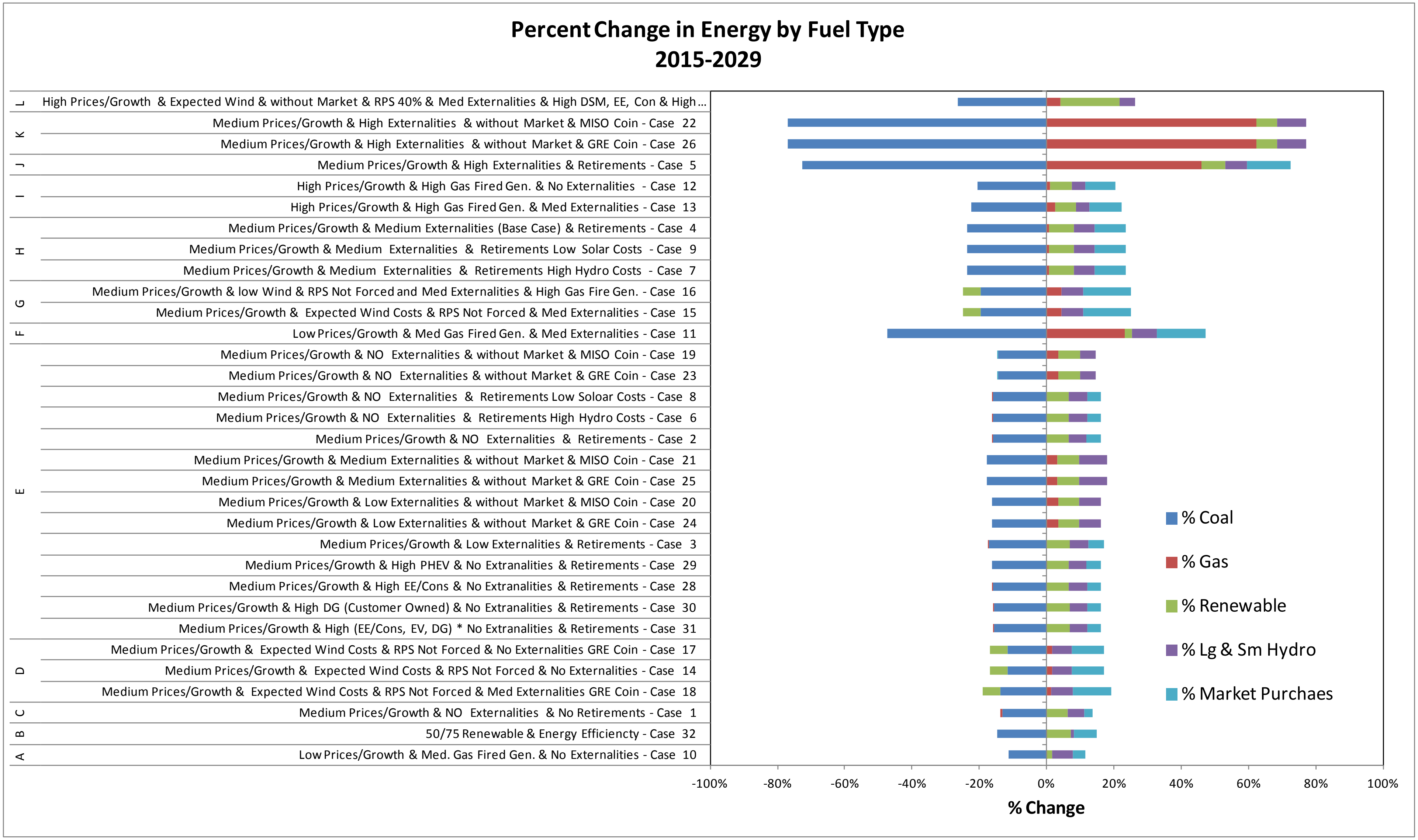

Figure 9-3. Comparison of resource additions and subtractions by fuel type for Expansion Plans and their cases.

9.4 Environmental Impact

In evaluating expansion plans, we looked at the expected CO_2 emissions over the forecast period. Table 9-5 below shows the average cumulative tons of CO_2 emitted in each of the expansion plans.

Table 9-5. Average cumulative tons CO_2 of each Expansion Plan.

Expansion Plan	CO_2 (tons)
A	170,455,918
B	181,673,236
C	180,898,623
D	177,702,397
E	175,478,213
F	153,448,343
G	176,004,878
H	176,004,878
I	191,081,098
J	151,910,461
K	176,214,318
L	141,206,590

The lowest CO_2 emissions are associated with those cases that have high externality costs.

GRE has reduced CO_2 emissions by 19 percent in 2013 from 2005 levels, based on the Minnesota Next Generation Act of 2007 methodology. These carbon dioxide emission reductions have occurred due to the removal of Power Purchase Agreements specifically associated with coal facilities, the addition of 469 MWs of wind, the addition of hydro energy and conservation and energy efficiency improvements.

Under Expansion Plan E, we expect CO_2 emissions reductions to continue as a result of the removal of the Genoa 3 contract from our portfolio and the addition of non-fossil hydro energy and wind energy over the forecast period. We expect to reach or exceed 15 percent reduction in CO_2 emissions in 2015.

Figure 9-4 reflects projected CO_2 emissions over the forecast period of Expansion Plan E, adjusted to reflect historic market interaction and generation production.

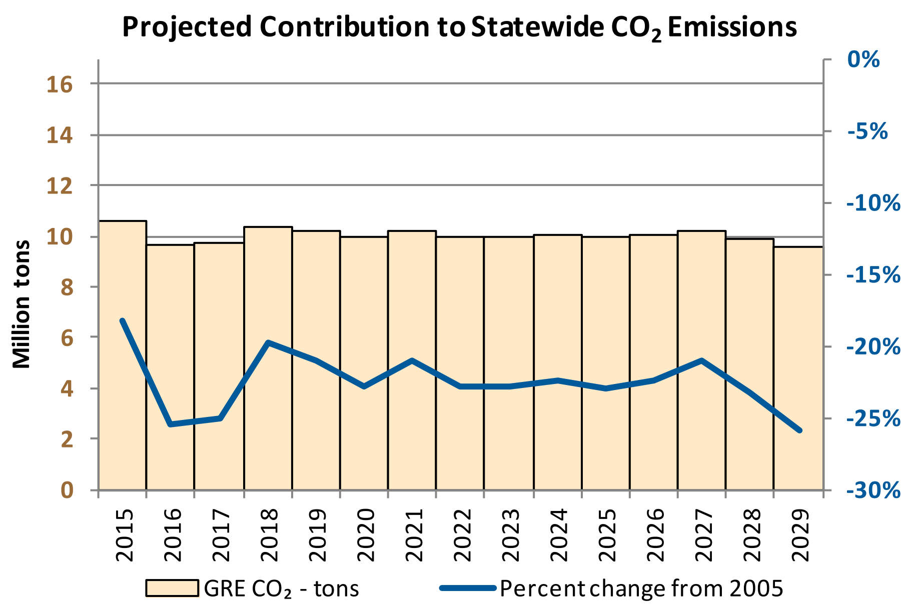

Figure 9-4. Projected CO_2 emissions in Expansion Plan E under the Minnesota Next Generation Act of 2007.

In Expansion Plan E our contribution to statewide CO_2 emissions will reach 26 percent below 2005 levels by 2029.

GRE has had an excellent track record of improving plant efficiencies over the years, and this trend is expected to continue. Increased plant efficiencies may result in lower carbon dioxide emissions. These unknown efficiencies are not reflected in the CO_2 emissions shown in Figure 9-4. The impacts related to any new regulations addressing emissions from existing sources will be reflected in future resource plans.

9.5 Risk

Risk was assessed by evaluating the impacts of market interaction, planning to MISO's peak compared to our own system peak, and fuel diversity.

Market Interaction

We analyzed our member needs and portfolio options under the assumption that GRE will continue to interact with the MISO market when it is economic to do so. In our modeling, market interactions were set to an upper limit of 400 MWs in any one hour in our analysis. This allowed a reasonable amount of interaction, but restricted the amount available and did not allow unlimited market reliance. This limit is lower than our historic hourly market interaction.

Member needs and options were also evaluated with no market interaction at all, which means that for those cases, market energy was not available to be selected in the model. Nine cases were modeled with no market interaction. The results show five out of the nine cases falling under Expansion Plan E. Three out of the nine cases considered retiring all our coal units except Spiritwood Station due to high externality costs. The Genoa 3 contract was terminated in all nine cases. There were no differences in resource additions or subtractions in the nine cases unless high externality costs were imposed. Among the nine cases with no market interaction, when no, low, and medium externality costs were considered, they yielded an average of 17.6 percent reduction in coal energy between 2015 and 2029.

Expansion Plans G, K, and L were eliminated due the assumption of no market interaction.

Expansion Plan E was selected even with no market interaction unless high externality costs are imposed.

Planning to MISO's Coincident Peak and Our Own System Peak

GRE is a MISO market participant, and as such, is required to comply with MISO's tariff, including Resource Adequacy and Module E. This means we plan our system resource availability and adequacy to meet our peak at the time of MISO's peak, or a coincident peak. More information on this is available in Section 8. Expansion Plan E is based on MISO's planning requirements.

As a sensitivity, GRE's resource needs were evaluated based solely on our own system peak, and not on our coincidence with MISO's peak. This sensitivity assumes that our system would operate as a stand-alone system, and not as a MISO market participant. The results of the six cases run with this sensitivity confirmed that Expansion Plan E is still the best outcome for our members. Three out of the six cases resulted in Expansion Plan E. The remaining three cases tested resulted in expansion plans with high externality costs and/or a forced decision not to meet Minnesota's renewable energy standard.

Fuel Diversity

A diverse generation fuel supply reduces the risk associated with any unusual occurrence that a single fuel may be subject to. For instance, a portfolio that relies only on one generation fuel type is subject to negative cost or reliability impacts that could result due to market or policy changes. A portfolio with multiple fuel types provides more reliability, operational flexibility and is less subject to individual fuel prices anomalies.

Expansion Plan B relies heavily on renewable energy.

Expansion Plan E continues generation fuel diversity that minimizes the risk of uncertainty associated with any single fuel type.

9.6 Selection of Expansion Plan

Expansion Plans that reflected unexpected outcomes of high or low energy prices, high or low energy and demand growth, high externalities costs and high PVRRs were eliminated. This eliminated Expansion Plans A, F, G, H, I, J, K and L from consideration. Expansion Plan B was eliminated because it results from a case where new hydro is not allowed as a resource option and it has a higher PVRR than Expansion Plan E. Expansion Plan C was removed from consideration since it does not allow coal generation retirements or coal contract terminations. Expansion Plan D was eliminated because it did not meet Minnesota's Renewable Energy Standard requirement.

Expansion Plan E covers a range of externality costs, regulatory costs, energy and demand growth rates, market interaction, coal prices, natural gas prices, conservation and energy efficiency, and allowance for coal retirements and coal contract terminations. Based on Expansion Plan E's assumptions and associated sensitivities, GRE believes this plan captures a range of risks associated with plausible future outcomes. It provides a plan that is robust in meeting and balancing our objectives of cost-effectiveness for our members, reliable service, environmental stewardship, while meeting all state and federal regulations, and providing optionality as our members' needs evolve.

Expansion Plan E continues to utilize our coal units, terminates an existing coal-based purchase contract, keeps costs lower than other plans, continues our reduction in carbon dioxide emissions, and maintains reliability by reducing our exposure to the MISO energy market. Without our efficient and reliable coal generation stations, GRE's members would be exposed to a higher level of market purchases, and would be more subject to market price risk.

Based on the Minnesota Rules' Factors to Consider of reliability, cost, environmental impact and risk, and based on our Triple Bottom Line of reliability, cost and environmental stewardship, we selected Expansion Plan E as our Preferred Plan.

10. FIVE YEAR ACTION PLAN

GRE plans and acts in the interest of our members. Consistent with our members' needs and our resource strategies, we will pursue the following actions over the next five years:

- Continue implementing conservation and energy efficiency programs while striving to meet or exceed the 1.5 percent per year Minnesota goal;
- Continue to accelerate depreciation on our two largest coal fired stations so that by 2028 the facilities will be fully depreciated;
- Continue to evaluate solar technologies and research the impacts to our member systems;
- Assist our members in developing solar generation in their service territories;
- Remain engaged in potential environmental regulation developments that may have impact on GRE;
- Identify a cost effective arrangement with Manitoba Hydro that will result in adding a zero carbon resource to GRE's portfolio;
- Work with DPC to terminate our long-term contractual obligation to purchase 50 percent of the capacity and energy from Genoa 3;
- Continue to work toward efficiency improvements at our generation facilities;
- Comply with the EPA's Clean Power Plan rules when they are issued;
- Develop an electric vehicle program to encourage the use of electric vehicles; and
- Engage external stakeholders in our business and our planning.

We believe these actions will continue to prepare us and our members for changes in the energy industry and in energy policy.

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11. LEGISLATIVE AND REGULATORY COMPLIANCE

11.1 Minnesota Renewable Energy Standard

GRE is in compliance with Minnesota's Renewable Energy Standard (RES). We have adequate renewable energy and RECs to meet Minnesota's 25 percent requirement in 2025. Based on expected load growth, we expect to need renewable energy in the late 2020's to comply with the RES. Our Preferred Plan includes the addition of 600 MWs of wind beginning in the year 2026 to meet this requirement. We note that non-fossil large hydro energy is not included in the Minnesota RES. However, our Preferred Plan adds new hydro energy in our portfolio in the 2020's. Table 11-1 below reflects our expectation for the volumes and timing of renewable energy additions to meet Minnesota's RES.

Table 11-1. Renewable energy additions to meet Minnesota's Renewable Energy Standard.

Year	MW Wind
2026	100
2027	100
2028	200
2029	200

This schedule of wind additions is an estimate based on our current load growth projections and expected wind capacity factors. Actual renewable energy additions may differ from the information provided in Table 11-1.

11.2 2014 Minnesota RES Rate Impact Update

On November 6, 2013, the Minnesota Public Utilities Commission (Commission) issued a Notice of Comment Period on Cost Impact Reports under Docket No. E999/CI-11-852. Comments were to address the PUC Staff's proposed general guiding principles for electric utilities' renewable energy cost impact reports and Staff's proposed format for a uniform reporting system. On April 18, 2014, the Commission issued a Notice of Supplemental Comment Period on Cost Impact Reports.

On May 8, 2014, GRE submitted comments in general support of the PUC Staff's adaptation of Xcel Energy's proposed template, with recommendations in a few areas.

On October 2, 2014 the Commission ruled on a consistent methodology to determine the RES rate impact. The timing of this decision did not allow us to include the final methodology in this resource plan. We will adopt the Commission's approved methodology for calculating the RES rate impact in our next resource plan.

As we did in our 2012 IRP filing, GRE looked at two ways to analyze the RES rate impact. We conducted a rate impact analysis using a forward looking modeling comparison. We also analyzed a rate impact using current renewable energy prices compared to MISO wholesale energy market prices.

Forward Looking Analysis

GRE evaluated 32 cases in our resource plan modeling. In Cases 14–18 the model was allowed to select wind and solar economically. These five cases reflect varying levels of Minnesota externalities and regulatory costs and capital costs of new wind and solar resources. In its optimization analysis, the model did not select wind or solar energy as economic in any of the five cases. In all other cases, GRE forced the model to select enough wind to meet the renewable energy requirements as discussed in Section 9.

We selected Expansion Plan E as our Preferred Plan in this IRP. Of the modeled individual cases that resulted in Expansion Plan E, Case 2 resulted in the lowest PVRR. Case 14 has the same set of assumptions as Case 2 except that it does not include the requirement that it must select renewable resources. Therefore, a comparison of Cases 2 and 14 provides the best forward looking rate impact of meeting the renewable energy requirements.

Over the 15-year forecast period the difference between Cases 2 and 14 is an increase in PVRR of $149.6 million or 2.2 percent. Because we do not need new resources until 2026, the annual wholesale rate impact due to additional renewable energy is zero until 2026. In each year of 2026, 2027, 2028 and 2029, the RES rate impact is $1.52 per MWh, $2.89 per MWh, $5.48 per MWh and $7.35 per MWh, respectively. Figure 11-1 shows these projected annual wholesale rate impacts beginning in 2026.

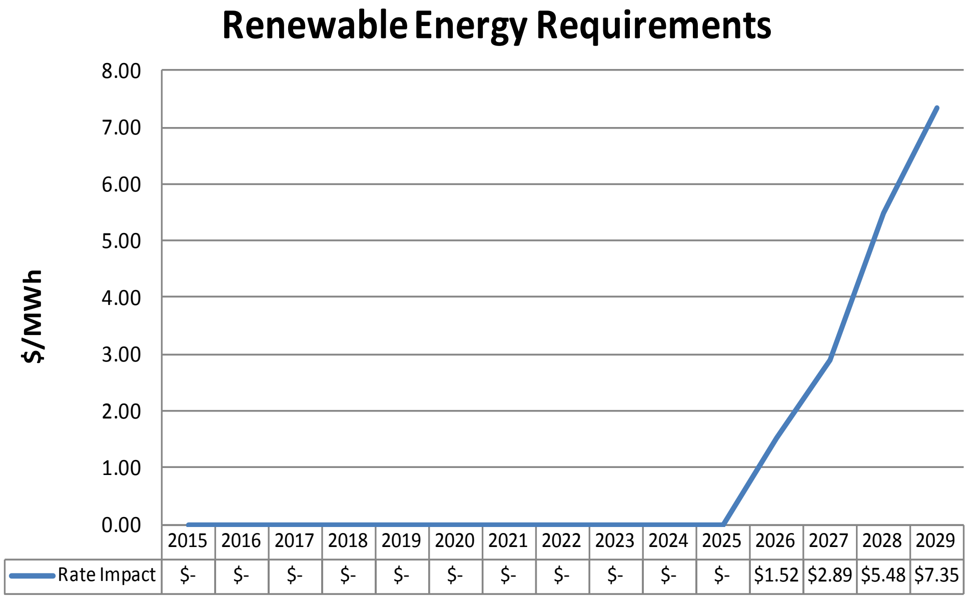

Figure 11-1. Rate impact of meeting Minnesota's Renewable Energy Standard by forward looking modeling.

Market Comparative Analysis

GRE filed our 2011 Minnesota RES Rate Impact Report (the Initial Report) to the Commission as required in Docket No. E999/CI-11-852. In the Initial Report, GRE's RES rate impact was determined by comparing the existing cost of previously procured wind resources to actual 2010 MISO energy revenue. This analysis provided a snapshot of the Minnesota RES rate impact in a single year.

In any particular year, the price we pay for existing renewable energy is likely to be different than actual MISO market prices. Currently, we are experiencing higher rates as a result of having existing renewable energy resources in our portfolio. Utilizing the methodology GRE used in our Initial Report, our members experienced a rate impact of more than $32 million just in 2013. This is because MISO market prices were below the cost of our renewable energy resources. The future impact will change as market prices rise or fall.

Regardless of the approach used to assess the rate impact, GRE wishes to note that mandates like the Minnesota RES may force us to make non-economic decisions that negatively impact our members' rates. Mandates like the Minnesota RES require that we secure resources that are not needed to meet our load requirements, and that may not be cost competitive with other resource options. In this resource plan, due to the Minnesota RES, we expect to acquire renewable resources beginning in 2026.

We have used the best information available to assess the rate impact to our members; however, due to the long planning horizon, it is difficult to determine the rate impact with certainty.

11.3 Use of Externalities and Compliance with Minnesota regulatory decisions

Many cases modeled included Commission approved externality and carbon regulatory costs. Carbon dioxide and criteria pollutant externality costs were applied to plant output as appropriate for a given plant's geographic location through 2018. Beginning in 2019 the carbon dioxide regulatory cost estimates were applied to carbon dioxide emissions from all plants regardless of geographic location. The other externality costs continued to be applied to emissions based on the geographic location of those emissions. Table 11-2 below summarizes the carbon dioxide cost values used in our modeling.

Table 11-2. Carbon dioxide cost values used in modeling.

	Years before 2019 (Environmental Cost)	2019 and after (Regulatory Cost)
Power Generated Inside Minnesota	Used the \$0.43 to \$4.46 per ton range pursuant to Commission Notice dated May 22, 2014	Used the \$9 to \$34 range established pursuant to Commission Order dated April 28, 2014
Power Generated Outside Minnesota (regardless of whether it is more than 200 miles from the Minnesota border)	No added cost: Environmental Cost for CO_2 set at \$0.00 in Commission Notice dated May 22, 2014	Used the \$9 to \$34 range established pursuant to Commission Order dated April 28, 2014

11.4 Community Based Energy Development

Given GRE's strong Minnesota RES compliance position, we have added only a small amount of new renewable resources since our last IRP filing which includes our solar PV demonstration projects described in Section 3. As GRE-owned facilities, they qualify as Community Based Energy Development (C-BED).

Table 11-3. C-BED projects owned or under contract and the amount of energy purchased.

Project Description	Estimated Annual Energy Production (MWh)
Federated Rural Electric Association 2.1 MW wind turbine	6,600
Nobles Cooperative Electric 2.1 MW wind turbine	6,600
GRE headquarters 200 kW wind turbine	175
GRE headquarters 344 kW solar PV	452
GRE distributed 40 kW solar PV	52

11.5 Previous Commission Orders and MN Statutes and Rules

A compliance table covering the Commission Order from GRE’s 2012 IRP and Minnesota Statutes and Rules related to resource planning can be found in Appendix A: Legislative and Regulatory Compliance Requirements.

11.6 Minnesota 7610 Electric Utility Report

GRE’s 2014 7610 Electric Utility Report is included in Appendix I: Minnesota 7610 Electric Utility Report.

GRE believes we are fully in compliance with Minnesota’s requirements for the RES, the RES rate impact, use of externalities and regulatory costs in our modeling, C-BED reporting, Commission Orders, Minnesota Statutes and Rules regarding resource planning, and submittal of the Minnesota 7610 electric utility report.

11.7 Preference for energy efficiency and renewable energy facilities

GRE’s Preferred Plan, Expansion Plan E, adds only renewable and non-fossil hydro resources. GRE modeled a case without addition of new large hydro since large hydro does not qualify to meet Minnesota’s Renewable Energy Standard. This is Case 32, which results in Expansion Plan B. Expansion Plan B has a higher PVRR than the Preferred Plan a.

11.8 Minnesota Emissions Reductions Goals

GRE has considered how we will meet Minnesota’s carbon dioxide emissions reductions goals. More information about this is included in Section 4. We expect to meet or exceed carbon dioxide emissions reductions that contribute to Minnesota’s goals in 2015 compared to 2005. Using our Preferred Plan, we expect to see a reduction in carbon dioxide emissions in 2025 of over 25 percent compared to 2005.

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LIST OF ACRONYMS

A

ACI	Active carbon injection
AMI	Advanced metering infrastructure
AR	All-Requirements member

B

BACT	Best Available Control Technology
BART	Regional Haze Regulations and Guidelines for Best Available Retrofit Technology
BFE	Blue Flint Ethanol
BSER	Best System of Emissions Reductions
Btu	British Thermal Units

C

CAGR	Compound annual growth rate
CAIR	Clean Air Interstate Rule
CapX2020	Capacity Expansion by 2020
C-BED	Community Based Energy Development
CCR	Coal combustion residuals
CCS	Carbon capture and sequestration (and Coal Creek Station)
CFC	National Rural Utility Cooperative Finance Corporation
CHP	Combined heat and power
CO_2	Carbon dioxide
Commission	Minnesota Public Utilities Commission
CP Node	Commercial participant (CP) node
CPI-U	Consumer price index-urban
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWIS	Cooling water intake structure

D

DC	Direct current
DER	Distributed Energy Resources
DER	Department of Energy Resources
DG	Distributed generation
DOE	U.S. Department of Energy
DPC	Dairyland Power Cooperative
DR	Demand response
DSI	Dry sorbent injection

DSM	Demand-side management
E	
EE	Energy efficiency
EERC	North Dakota Energy and Environmental Research Center
EF	Energy factor
eGRID	Environmental Protection Agency's Emissions Generation Resource Integrated Database
EGU	Electric generating units
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERERS	Elk River Energy Recovery Station
ERMU	Elk River Municipal Utilities
ERRPP	Elk River Resource Processing Plant
ESPS	Existing Source Performance Standards
ETS	Electric thermal storage
EV	Electric vehicle
F	
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
Fixed	Fixed Obligation member
G	
Genoa 3	Dairyland Power Cooperative Genoa Unit 3
GHG	Greenhouse gas
GRE	Great River Energy
GW	Gigawatt
GWh	Gigawatt-hour
H	
HVDC	High-voltage direct current
HPWH	Heat pump water heater
I	
ICAP	Installed capacity rating, megawatts
IGCC	Integrated gasification combined cycle
IRP	Integrated Resource Plan
ISBM	DOE's SunShot Innovative Solar Business Model
K	
kV	Kilovolt
kW	Kilowatt

kWh	Kilowatt-hour
L	
LBA	Local Balancing Authority
LMP	Locational Market Prices
M	
MAPP	Mid-continent Area Power Pool
MATS	Mercury and Air Toxics Standards
Members	GRE member-owner cooperatives
MGD	Million gallons per day
MHEB	Manitoba Hydro Electric Board
MISO	Midcontinent Independent System Operator
MN CIP	Minnesota Conservation Improvement Programs
MN DER	Minnesota Department of Commerce, Division of Energy Resources
MN RES	Minnesota Renewable Energy Standard
MOU	Memorandum of Understanding
M-RETS	Midwest Renewable Energy Tracking System
MROW	Midwest Reliability Organization West
MTEP	MISO Transmission Expansion Plan
MTO	Midwest Transmission Owners
MW	Megawatt
MWh	Megawatt-hour
N	
NAAQS	National Ambient Air Quality Standards
NDDH	North Dakota Department of Health
NERC	North American Electric Reliability Corporation
NGCC	Natural-gas fired combined cycle
NISC	National Information Solutions Cooperative
NO_X	Nitric oxide and nitrogen dioxide
NRCO	National Renewables Cooperative Organization
NRDC	National Resource Defense Council
NRECA	National Rural Electric Cooperative Association
P	
PAR	Planning and Risk
PCB	Polychlorinated biphenyl
PPA	Power Purchase Agreement
PRB	Powder River Basin
Preferred Plan	GRE’s preferred expansion plan
PSWH	Peak shave water heating
PV	Photovoltaic

PVRR Present Value of Revenue Requirements

R

RA Resource Adequacy

RCRA Resource Conservation and Recovery Act

RDF Refuse-derived fuel

REC Renewable Energy Certificates (or Credits)

RES Minnesota Renewable Energy Standard

RFP Request for proposals

RMI Rocky Mountain Institute

S

SF_6 Sulfer hexafluoride

SGDP DOE Smart Grid Demonstration Project

SIP State Implementation Plan

SO_2 Sulfur dioxide

SMEC Southern Minnesota Energy Cooperative

SPM Sub-regional Planning Meeting

SUNDA DOE SunShot Initiative Solar Utility Network Deployment Acceleration

T

TMDL Total maximum daily load

TRC Total resource cost test

U

UCAP Unforced capacity, megawatts

V

VFD Variable frequency drive (or device)

VOM Variable operations and maintenance

W

WI REO Wisconsin Renewable Energy Objective