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ENERGY®

12300 Elm Creek • Maple Grove, Minnesota 55369-4718 • 763-445-6118 • Fax 763-445-6918

June 30, 2011

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PUBLIC SERVICE COMMISSION

Ms. Illona Jeffcoat-Sacco
Executive Director
North Dakota Public Service Commission
600 East Boulevard Avenue – Department 408
Bismarck, ND 58505-0480

Dear Ms. Jeffcoat-Sacco:

Enclosed are an original and ten copies of *Great River Energy's (GRE) North Dakota Ten-Year Plan Report, 2011-2020* (Report) to the North Dakota Public Service Commission (Commission) as required by Chapter 49-22-04 of the North Dakota Century Code (NDCC).

In accordance with Chapter 69-06-02-02 of the NDCC, GRE has provided a copy or notice of the Report to the necessary parties.

GRE has included an extra copy of the Report and a self-addressed stamped envelope and requests that the Commission provide GRE with a file stamped copy.

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

Sincerely,

GREAT RIVER ENERGY

Laureen R. McCalib

Laureen L. Ross McCalib
Manager, Resource Planning

Enclosures (11)

Cc: NDPSC (10)
County Auditors (4)
ND State Agencies and Officials (Letters of Confirmation only)

Great River Energy's

North Dakota Ten-Year Plan Report

2011-2020

Submitted to
The North Dakota Public Service Commission

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

July 1, 2011

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INTRODUCTION

This report was prepared in accordance with the North Dakota Public Service Commission's (Commission) Guidelines (Guidelines) for compliance with the requirements of Chapter 49-22-04 of the North Dakota Century Code.

Great River Energy has concluded that some information that would be provided under Sections E and F and Exhibits 3 and 5 pursuant to the Guidelines qualifies as Critical Energy Infrastructure Information (CEII) and, therefore, has not included the information in these pages. GRE offers to provide the information to the Commission upon request.

SECTION A: Existing Energy Conversion Facilities

Great River Energy's capacity consists of coal, refuse-derived fuel (RDF), wind, natural gas, and oil-fired units. The coal-fired plants are located at Stanton and Underwood, North Dakota. GRE has added no new Energy Conversion Facilities since submitting its 2010 report:

GRE currently has no plans to retire any of its existing energy conversion facilities within the next ten years.

Table 1 below shows the summer season ratings of GRE's generating plants.

Table 1- GRE's Existing Energy Conversion Facilities

Unit Name	Summer Capacity (MW)
Coal Creek Station 1 (Coal)	557.6
Coal Creek Station 2 (Coal)	565.0
Stanton Station (Coal)	188.0
Genoa 3 (share of coal plant)	123.0
Elk River Station 1-3 (RDF)	33.3
Chandler Wind *	6.0
Christoffer Wind *	5.5
McNeilus Wind *	5.7
Trimont Wind *	100.0
Prairie Star Wind *	100.0
Elm Creek Wind *	100.0
Pleasant Valley Station (Peaking)	413.8
Lakefield Junction (Peaking)	499.5
Cambridge CT (Peaking)	21.5
Cambridge CT2 (Peaking)	155.1
Maple Lake CT (Peaking)	18.9
Rock Lake CT (Peaking)	20.2
St. Bonifacius CT (Peaking)	59.6
Elk River CT (Peaking)	182.5
Hastings (Diesel)	8.8
Lake Marion (Diesel)	8.8
Moose Lake (Diesel)	9.8
Arrowhead (Diesel)	n/a
Coal Creek Station diesel	n/a
Stanton Station diesel	n/a
* Wind ratings are nameplate	

SECTION B: Energy Conversion Facilities Under Construction

North Dakota. GRE is constructing a combined heat and power project at Spiritwood. The project will produce process steam for the adjacent Cargill malting facility as well as electric energy that will be sold into the Midwest Independent Transmission System Operator (MISO) energy market. The project has additional process steam capacity available due to cancellation of an ethanol plant that had been proposed near the site. GRE is actively searching for an additional steam customer.

The primary fuel for the project will be refined (dried) lignite from Coal Creek Station. The plant is designed to provide approximately 64 MW of baseload capacity at an overall thermal efficiency of approximately 66% with full utilization of the plant's process steam. The project also includes natural gas-fired boilers to provide a back-up source of process steam. When the process steam needs are being met by the natural gas-fired boilers, the power plant is capable of producing an additional 35 MW of peaking capacity.

Construction of the power plant is complete and commissioning is underway. Commissioning will be complete by the end of 2011, the date of commercial operation is under review. The project is interconnected with Otter Tail Power Company transmission facilities that are part of the MISO system. Interconnection arrangements for the first 50 MW of plant capacity are in place. Arrangements for the remaining plant capacity are under study by MISO and GRE.

SECTION C: Proposed Energy Conversion Facilities on Which Construction is Intended Within the Ensuing Five Years

Other than those noted in Sections A and B, GRE has no other specific proposed energy conversion facilities as defined by Chapter 49-22-03 of the North Dakota Century Code.

While GRE has identified no specific facilities for construction in the next five years, GRE continues to evaluate its future needs, including additional renewable energy resources to comply with Minnesota's Renewable Energy Standard.

SECTION D: Proposed Energy Conversion Facilities During the Next Ten-Year Time Period

GRE has no specific proposed energy conversion facilities as defined by Chapter 49-22-03 of the North Dakota Century Code.

GRE continues to evaluate its future needs, including additional renewable energy resources to comply with Minnesota's Renewable Energy Standard.

SECTION E: Existing Transmission Facilities (Electric)

GRE has concluded that its existing transmission facilities qualify as CEII. A map of the transmission facilities that GRE owns and operates in North Dakota will be made available upon request. Summary information on GRE's North Dakota transmission facilities is provided in Table 2.

Table 2 – GRE's Existing Electric Transmission Facilities in North Dakota

Facility	Voltage (kV)	AC/DC	Install Year
Stanton – Leland Olds	230	AC	1966
Stanton – Mchenry Tap	230	AC	1966
Mchenry Tap – Mchenry	230	AC	1966
Mchenry – Balta	230	AC	1966
Balta – Ramsey	230	AC	1966
Ramsey – Prairie	230	AC	1966
Stanton – Square Butte	230	AC	1966
Mchenry Tap – Coal Creek	230	AC	1979
Stanton - Coal Creek	230	AC	1979
Coal Creek – Dickinson, Minnesota	± 400	DC	1979

GRE is not planning to retire any existing transmission facilities within the next ten years.

The Commission's Guidelines require a copy of Federal Energy Regulatory Commission (FERC) Form 12. The information previously provided in FERC Form 12 is now found in FERC Form 715. A copy of GRE's most recent filing is available upon request.

SECTION F: Existing Transmission Facilities (Pipeline)

GRE has a water pipeline and accompanying pumping station located near Coal Creek Station that has been in service since August 1, 1979. GRE concludes that the information qualifies as CEII and has not provided it in this document. However, specific information on the facilities and a map will be provided upon request.

SECTION G: Proposed Transmission Facilities on Which Construction is Intended Within the Ensuing Five Years (Electric)

GRE's participation in the CapX2020 transmission initiative is described in Section J. One of three 345 kV transmission lines, Fargo-Monticello, making up "Phase I" would begin at a new Bison Substation near Fargo and terminate at Monticello, Minnesota, with intermediate substations near Alexandria and St. Cloud, Minnesota. General corridors for the North Dakota line segment have been identified and activities for acquiring permits are underway, which include the following major permits:

- North Dakota:
  - Certificate of Public Convenience and Necessity (CPCN)
  - Certificate of Corridor Compatibility
  - Route Permit
- Federal
  - U.S. Army Corps of Engineers
  - U.S. Fish and Wildlife Service
  - U.S. Federal Aviation Administration
  - U.S. Department of the Treasury, Bureau of Alcohol, Tobacco, Firearms and Explosives

On May 22, 2009, the Minnesota Public Utilities Commission issued an order approving a Certificate of Need for the three CapX2020 345 kV projects, including the project that will terminate in North Dakota. The project segments are targeted for in-service dates in the 2011-2015 timeframe.

On July 8, 2010, the Minnesota Public Utilities Commission granted a Route Permit for the 345 kV transmission segment between Monticello and St. Cloud, MN.

On June 10, 2011, the Minnesota Public Utilities Commission granted a Route Permit for the 345 kV transmission segment between the ND/MN border and St. Cloud, MN.

Additional information can be found at www.capx2020.com.

SECTION H: Proposed Transmission Facilities on Which Construction is Intended Within the Ensuing Five Years (Pipeline)

None.

SECTION I: Proposed Transmission Facilities During the Next Ten-Year Period (Electric and Pipeline)

Interconnection arrangements for the first 50 MW of Spiritwood capacity are in place. MISO is currently evaluating the remaining 49 MW capacity from Spiritwood which may require transmission additions, Study analysis to date has identified the need to upgrade an existing Ottertail 115 kV line in the Jamestown area..

SECTION J: Regional Coordination

The electric grid is heavily interconnected and must be evaluated, operated, and expanded in a coordinated manner to assure reliability and cost-effectiveness. GRE's transmission planning is closely coordinated with other organizations. GRE is a member of and participates directly in several regional entities:

- The Midwest Independent Transmission System Operator (MISO), which administers a tariff providing for regional transmission services, energy and ancillary services markets, and resource adequacy requirements. MISO also has responsibilities for regional transmission planning, coordination, and expansion. GRE is a full member and market participant. Further information about MISO is available on-line at *www.misoenergy.org.* MISO's transmission expansion plans (MTEP-2010 being the most-recent approved plan) are also available at their web site under the "Planning" tab and contained in the "Transmission Expansion Planning (MTEP)" link.
- The Midwest Reliability Organization (MRO), a non-profit organization of regional utilities established to develop regional reliability standards and ensure compliance with standards of the North American Electric Reliability Corporation (NERC) as well as its own. Further information about MRO is available on-line at *www.midwestreliability.org* and about NERC at *www.nerc.com.*

- The Mid-continent Area Power Pool (MAPP), which has historically provided resource pooling and transmission coordination functions for its members across a large part of the upper Midwest. For GRE and other MISO members, these functions have largely been transitioned to MISO. GRE's transmission system is no longer part of MAPP and GRE is no longer a member of the MAPP generation reserve sharing pool. Further information about MAPP is available on-line at www.mapp.org.
- MISO conducts Subregional Planning Meetings (SPMs) four times each year to provide a forum for coordination and discussion of transmission issues and proposed projects among utilities and other interested stakeholders.
- The Minnesota Transmission Owners (MTO) group, a consortium of 16 sponsoring utilities and three participating government agencies, fulfills the utilities statutory obligations for transmission planning in the state of Minnesota. These obligations include the development of the Minnesota Biennial Transmission Plan, as well as studies associated with meeting the Minnesota Renewable Energy Standard (RES) requirements. Further information about the MTO group is available at www.minnelectrans.com.
- CapX2020, a joint initiative of eleven regional transmission utilities to develop a long-range vision and transmission expansion projects to ensure that load in the region can be served reliably, provide outlet capability for renewable and other generation additions and support regional reliability of the transmission system. As a first phase of transmission expansion, all four CapX2020 projects have received Certificates of Need from the Minnesota Public Utilities Commission.
  - The **Hampton – Rochester - La Crosse 345 kV Project** is an approximately 140-mile transmission line project between the southeast corner of the Twin Cities, connecting to a new substation in north Rochester, continuing eastward crossing the Minnesota River near Alma, Wisconsin and continuing south in Wisconsin to La Crosse, Wisconsin. This project also includes a new 161 kV transmission line between the new North Rochester Substation and the existing North Hills substation in northwest Rochester.
  - The **Fargo - Monticello 345 kV Project** is an approximately 240-mile, 345 kV transmission line between Monticello, St. Cloud, Alexandria and Fargo, North Dakota. The project has received two route permits from the MN Public Utilities Commission. The first route permit is for a 28-mile transmission line between Monticello, Minnesota to a new Quarry substation near St. Cloud, Minnesota. The project includes a 115 kV transmission line connector between the existing St. Cloud to Sauk River 115 kV line and a new Quarry substation. The second route permit is for an approximately 230-mile transmission line between the new Quarry substation near St. Cloud, Minnesota and the MN / ND border near Fargo, North Dakota.
  - The **Brookings County – Hampton 345 kV Project** is an approximately 240-mile, 345 kV transmission line between Brookings County, South Dakota and the southeast corner of the Twin Cities. This project includes a 25-mile, 345 kV segment from the Lyon County substation near Marshall, Minnesota to a new Hazel Creek Substation in the Granite Falls area, a six-mile, 230 kV transmission line from Hazel Creek to the Minnesota Valley Substation in Granite Falls and a 5-mile 115 kV transmission line from Cedar Mountain substation to the Franklin substation. The final MN route permit was approved by the MN Public Utilities Commission in April 2011. The South Dakota Public Utilities Commission approved the facility permit in June 2011.

- The **Bemidji - Grand Rapids 230 kV Project** is a 68-mile, 230 kV transmission line project from the Wilton substation near Bemidji, Minnesota to the Boswell substation near Grand Rapids, Minnesota. The MN Certificate of Need and route permits have been approved by the MN Public Utilities Commission.

CapX2020 and the MTO group have engaged in several planning studies that will provide an updated vision of the transmission system to meet needs further into the future. That includes delivering renewable energy in quantities sufficient to meet the renewable energy requirements of states in the region. The studies were closely coordinated with MISO, neighboring transmission owning utilities and a diverse group of stakeholders formalized as the Technical Review Committee. MISO also has numerous studies underway with similar objectives, but that consider a broader geographic area. Great River Energy and the CapX2020 utilities actively participate in these studies. The studies listed below were intended to provide a roadmap for cost effective transmission expansion that will integrate well with future scenarios, meet future needs and provide flexibility for changing conditions.

- Southwest Twin Cities – Granite Falls Transmission Upgrade & Minnesota Renewable Energy Standard Update: This study provides an updated Vision Plan that addresses reliability needs, the 2016 & 2020 milestones of the Minnesota Renewable Energy Standard, and regional renewable energy supply needs. It has been completed and can be found at www.minnelectrans.com.
- Capacity Validation Study (CVS): This study focused on the impacts that specified transmission projects, taken individually or in combination, have on the ability to incorporate additional generation into the system. It provides an estimate of how much additional generation could be added at assumed locations by combinations of transmission projects. This study also sought to verify and validate the transfer capabilities estimated by other project studies. It has been completed and can be found at www.minnelectrans.com.
- Facilities Study: Manitoba Hydro TSR 500 kV Option 1: This study was commissioned by MISO to evaluate a transmission design alternative for adding 1100 MWs of hydro generation from Manitoba, Canada to the Upper Midwest U.S. The study results were issued in May 2010 and are available through MISO.
- Dispersed Renewable Generation (DRG) studies: Dispersed renewable generation studies were required as part of the Minnesota's Next Generation Act of 2007. Phase One was completed in June 2008; Phase Two was completed in September 2009. The studies are available on the Minnesota Department of Commerce, Division of Energy Resources website.

Further information about CapX2020, the proposed projects, and studies are available on-line at *www.capx2020.com and www.minnelectrans.com*.

Great River Energy is a participant in the Upper Midwest Transmission Development Initiative (UMTDI). UMTDI was developed by the governors offices and public utilities commission of five Midwest states (Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin) to generate consensus around a plan and cost allocation for transmission development in the Upper Midwest region, and to promote economic development, assure reliability and provide access to and transport of wind and other renewable energy sources from source to load.

- Great River Energy was a participant in the Regional Generation Outlet Study (RGOS) led by MISO. The goal of the RGOS effort was to develop transmission projects that facilitate the state renewable energy mandates in the Midwest Independent System Operator (MISO) footprint. The RGOS served to deliver one plan to Appendix B of the MISO Transmission Expansion Plan (MTEP) 2010 Report, as well as a RGOS report of results and findings. The selected plan represented a least regrets portfolio solution based on detailed design development, sensitivity case analysis, and value metric application.

- After the completion of the RGOS, MISO formed a stakeholder task force for analysis on a portfolio of nineteen transmission projects to determine whether they will be granted MISO wide cost allocation status. These projects are spread across the MISO footprint and includes a line in ND and connections toward eastern MISO. MISO will determine whether the line projects help meet public policy (renewable standards), exceed economic thresholds and strengthen grid robustness. This is scheduled to be completed fall of 2011. Projects that are determined to be multi-valued will be recommended to the MISO Board of Director for MVP cost allocation in December of 2011, which would qualify them for 100% MISO cost sharing.
- The federal American Recovery and Reinvestment Act (ARRA) has directed the development of interconnection-based transmission plans. Twenty-four planning authorities in the Eastern Interconnection are collaborating in a planning process known as the Eastern Interconnection Planning Collaborative (EIPC). This EIPC process will ultimately generate an interconnection-wide transmission plan for three scenarios chosen from seventy-two "generation futures." Important dates include:
  - December 2011 – interim report containing the results of seventy-two generation futures as well as the three scenarios chosen for further analysis,
  - Early 2012 – development of transmission plan for three chosen scenarios, and
  - December 2012 – final report submitted to Department of Energy.

Recommended Measures for Regional Coordination:

None beyond the activities described here in Section J.

SECTION K: Environmental Information

Clean Air Act Title IV Requirements. Coal Creek Station and Stanton Station, as well as several of GRE's combustion turbine stations, have affected units under the federal acid rain regulations (Title IV of the Clean Air Act Amendments).

These regulations limit NO_X 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 have complied with their applicable limits through the installation of low NO_X burners and other combustion controls including over-fire air.

The acid rain program also places limits on emissions of SO_2 and creates a market for SO_2 emission allowances. Under this program, the U.S. Environmental Protection Agency (EPA) allots a specified number of SO_2 allowances to each unit for each year. Utilities are free to:

- "under-control" and buy allowances,
- "over-control" and sell allowances, or
  - hold allowances for future use;
  - trade or transfer allowances in power sales or other transactions,
  - pool allowances with other utilities to mitigate risk, or
  - use allowance futures contracts and options to hedge against future price changes.

Upgrades have been made to the scrubbers on both units at Coal Creek Station and on Unit 10 at Stanton Station. Coal Creek Station's two units are allotted 44,497 allowances per year. GRE also has installed a pollution control, energy recovery and emission reduction project at Coal Creek Station whereby the plant provides steam for an adjacent ethanol plant. Further, Coal Creek Station has installed DryFining™ that reduces SOx and NOx, among other pollutants, while improving overall plant efficiency. (See Coal Drying Section)

Stanton Station's two units are allotted 8,781 allowances per year. In 2004, Stanton Station switched from lignite to Powder River Basin (PRB) coal, resulting in lower emissions. Stanton Station is currently designing a SO_2 scrubber for Unit 1.

No additional modifications should be required for continued compliance with the SO_2 provisions of the acid rain program.

Fly Ash Sales. GRE has actively pursued beneficial reuse opportunities for the coal combustion products generated at Coal Creek Station and Stanton Station.

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 ten years GRE has been very successful in finding alternative uses for it. It is primarily used as a partial replacement for cement, which makes the concrete 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 new 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, greenhouse gas emissions are estimated to be reduced by just over 0.8 tons. Since 1998, more than 2.5 million cumulative tons of CO_2 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 their fly ash utilization in the oil field industry.

Through the beneficial use of ash, GRE also avoids storing the ash in landfills, resulting in cost savings of over $4 per ton. Since 1998, over $10 million in cumulative landfilling costs have been avoided through beneficial use.

Coal Combustion Products (CCP) Disposal. Recent developments could potentially disrupt the market for ash use. 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

CCPs. EPA is considering options for regulating the disposal of all CCPs. One of their options is to regulate these materials as "hazardous waste" under 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 beneficial use market including fly ash sales. Consumers and sellers could be averse to the risk of handling a material with potential RCRA Subtitle C liabilities. In some states, it could make the use of the materials illegal. EPA is also considering regulation of CCPs 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 proposed CCP rule is expected in 2013.

Cogeneration for an Ethanol Plant. GRE completed integration of Blue Flint Ethanol with Coal Creek Station, which provides steam for their distiller's grain drying and other system thermal requirements. In addition to the benefit of using low pressure steam that would normally be unused, the project will result in much lower emissions than a stand-alone ethanol project.

The primary benefit of locating the ethanol plant adjacent to Coal Creek Station is to allow for beneficial use of low temperature/quality energy from Coal Creek Station by the ethanol facility. Approximately 60 percent of the process steam for the ethanol facility will come from recovery and use of low pressure steam at Coal Creek Station. This steam is not usable in Coal Creek Station's steam cycle, and it would normally be rejected to the cooling towers as waste heat. The remaining 40 percent of the ethanol plant's process steam needs are for higher pressure steam, which also comes from Coal Creek Station.

Coal Drying Project. In February 2003, the U.S. Department of Energy selected GRE's Coal Creek Station to participate in a clean coal technology project. Through the project, Coal Creek Station conducted a large-scale coal-drying study to determine if it is feasible to dry large quantities of lignite for use at the plant. Lignite has a high moisture and ash content. By reducing the moisture and ash content, less coal is required to generate the same amount of electricity. This also results in fewer emissions. Through the project, the moisture content of lignite will be reduced from 38 percent to less than 30 percent. This will improve the quality of lignite - making it closer to the quality of PRB sub-bituminous coal from Montana and Wyoming. As a result, efficiencies will increase by 2.8 to 4 percent. Sulfur dioxide emissions are expected to decrease by 40 percent. Mercury, carbon dioxide, nitrogen oxides and particulate emissions are also all expected to decrease due to the reduction of the flue gas volume and dryer density separation.

The dryer technology (DryFining™) is being applied to both Coal Creek units. Construction of the dryers has been completed and the process began commercial operation in December 2009. GRE is pursuing marketing of the dryer technology for use in other power plants; nearly 50% of global coal is low-rank.

Future Environmental Regulations. Following is a discussion of future environmental regulations that may affect GRE's operations.

> **Regional Haze.** EPA published final regional haze regulations in 1999. The goal of these regulations is to improve visibility in Class 1 areas, such as national parks and wilderness areas, by reaching "natural conditions" in 2064. The first phase of this rule requires certain power plants to install Best Available Retrofit Technology (BART) to control SO_2, NO_X and Particulate Matter (PM). Since 2005, GRE has been working closely with the North Dakota Department of Health (NDDH) and has provided detailed BART analyses for each affected unit that identifies feasible control options for each pollutant, cost estimates for the respective controls, expected emission rates and

associated visibility improvements for each combination of controls. NDDH issued their final BART determinations for public comment as part of their Regional Haze State Implementation Plan (SIP) in January 2010. These emission controls must be installed and operational no later than five years after EPA approves the North Dakota BART State Implementation Plan (SIP), which is tentatively anticipated in 2016. Coal Creek and Stanton stations have been working diligently on their BART control strategies and do not anticipate any difficulty meeting the regulatory timelines.

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 2023 for any applicable control requirements.

National Ambient Air Quality Standards. EPA periodically reviews the National Ambient Air Quality Standards (NAAQS) to determine the protectiveness of the existing standard. In 2008, the eight-hour ozone standard was changed from 0.08 parts per million to 0.075 parts per million. The one-hour ozone standard was revoked except in limited areas of the country. EPA is currently reviewing comments on proposed revisions to the 2008 ozone standard to potentially lower it. A new fine particulate matter (PM2.5) standard was created in 1997 at a maximum annual average of 15 micrograms per cubic meter and the maximum 24-hour average was revised in 2006 to be 35 micrograms per cubic meter. EPA is considering changes to the PM2.5 standards by October 2011. Also of note, EPA has promulgated new primary standards for NO_2 and SO_2 in 2010, and is considering a combined NO_2/SO_2 secondary standard.

Minnesota and North Dakota are currently considered to be "in attainment" with the revised ozone and PM2.5 NAAQS. Some counties in Minnesota and North Dakota may be in "non-attainment" depending on whether and to what extent EPA lowers the ozone standard. Minnesota and North Dakota are evaluating their attainment status with respect to the new NO_2 and SO_2 standards.

Mercury and Hazardous Air Pollutants (HAP). Since the late 1990s, GRE has been an industry leader in researching mercury reduction technologies at our plants. We continue to work with partners such as the Electric Power Research Institute (EPRI), U.S. Department of Energy (DOE), and North Dakota's Energy & Environmental Research Center (EERC) to identify and test novel mercury reduction technologies.

In 2005, the EPA published its Clean Air Mercury Rule (CAMR). Coal Creek and Stanton stations were to be covered by this rule and had made plans to install controls and monitor their emissions in compliance with this cap and trade program. The CAMR rule was then vacated by the U.S. Court of Appeals for the DC Circuit on February 8, 2008.

EPA is now required to develop Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act. EPA issued a proposed rule in the Federal Register on May 3, 2011, and is accepting comments, which are due in August. The proposed rule establishing emission limits for essentially 4 categories of hazardous air pollutants, mercury, non-mercury metals, acid gases and volatile organic compounds (VOCs.) Coal Creek, Stanton and Spiritwood Station are subject to the proposed 4.0 lb/mmBtu mercury emission rate since these units were designed for <8300 Btu/lb coal. With respect to non-mercury metals, EPA has allowed particulate matter (PM) surrogate monitoring as an alternative to routine stack testing. Coal Creek and Stanton have performed some limited non-mercury HAP metal testing and appear to comply with the proposed total metal HAP limits, through the use of existing baghouses and electrostatic precipitators (ESP), but with limited margin for emissions variability. On acid gases, EPA has proposed either an hydrochloric acid or an SO_2 emission limit. Coal Creek, Stanton and Spiritwood stations will meet the proposed acid gas HAP limits through existing or planned BART controls, as noted above. On VOC emissions, EPA has proposed work practice standards including annual tune-ups and burner NO_x/CO optimization.

Given the extent and coverage of this proposed rule, it is clear that significant comments will be submitted and the final rule is likely to change from the proposed rule. The final rule is expected by November 2011, with the eventual limits applying three years thereafter, or November 2014, if EPA holds to the current schedule. North Dakota can allow for up to a 1-year extension on the 3 year compliance deadline, if they deem it necessary. Since GRE has conducted significant mercury reduction research at our plants, and is planning more plant based research in 2011, we are uniquely positioned to respond to a MACT regulatory program once finalized. Depending on the final MACT rule and associated limits, additional plant emission controls and monitoring may be required, with a relatively tight timeframe for design and construction.

Greenhouse Gas Emissions. In late 2009, EPA issued its final Greenhouse Gas Reporting Rule, which requires Great River Energy facilities to track and report greenhouse gas emissions. Great River Energy has been tracking and reporting CO_2 emissions to EPA for all Acid Rain affected units since 1995. The new EPA GHG reporting rule increases the number of GHGs that must be reported and adds additional smaller emission units at our plants to our existing tracking and reporting compliance programs. Sulfur hexafluoride (SF_6) emissions from our transmission facilities must also be reported.

In addition, in May 2010 EPA promulgated the final Greenhouse Gas (GHG) Tailoring Rule, which regulates for the first time GHGs under the Clean Air Act. Facilities making "major modifications," as defined for criteria pollutants under New Source Review (NSR), must now complete best available control technology (BACT) evaluations for GHGs starting in 2011.

GRE is active in trying to shape federal environmental legislation and regulation in concert with National Rural Electric Cooperative Association and other associations. GRE continues to be a funding member of the Energy & Environmental Research Center's Plains CO_2 Reduction partnership (PCO_2R) which conducts research into CO_2 sequestration. Internally, GRE has an established cross-functional carbon team that is evaluating opportunities for carbon reduction and offsets. In assessing generating technologies to meet its customers' needs, GRE includes externality costs for CO_2 emissions.

Impaired Waters and Total Maximum Daily Loads. Every two years EPA, under the Clean Water Act, requires states to publish and submit an updated list of waters that do not meet designated uses due to pollutant impacts. The §303(d) impaired waters list includes lakes, streams and rivers with impairments for use as drinking water, fishable waters, swimming, industrial use and/or irrigation.

Once a water body is listed, the state must begin the process of addressing the impairment. The first stage of this process is development of a total maximum daily load (TMDL). A TMDL is the total maximum daily pollutant load a water body can receive from all sources while maintaining applicable water quality standards and supporting the water body's designated uses.

The development of a TMDL is designed to assess the load on a water body from point sources, non-point sources, and natural background conditions. Once these loads are quantified, each source can be assigned a given amount of pollutant load expected to ensure the receiving water body will meet water quality standards and designated uses.

At this time, states are generally in the water body assessment phase, but TMDLs have either been developed or are in development for an increasing number of water bodies. As this process proceeds, TMDLs will likely be developed for water bodies to which GRE either has or is seeking permitted discharges. This could change discharge limits, result in limits for additional analytical parameters or even possibly preclude permitting of a new or expanded discharge to a given water body. The most likely affected parameters include mercury, phosphorous, total suspended solids, and temperature.

In many instances the impairments mentioned above have significant contributions from non-point and natural background sources. Due to the difficulty in controlling the loads from these sources, significant reduction goals may be allocated to point sources such as GRE's permitted discharges. Retrofitting existing facilities and implementing new pollutant reduction technologies will likely require significant capital expenditure to achieve relatively small reductions for a given pollutant. Based on this it appears pollutant trading and restoration projects will play a significant role in the TMDL process. GRE will continue to monitor TMDL development and assess potential impacts to our facilities.

Effluent Limitation Guidelines. EPA recently sent an Information Collection Request (ICR) to all coal fired electric generating units regarding effluent guideline limitations. This included Coal Creek and Stanton stations. The information supplied to EPA will be used to develop new effluent guideline limits for NPDES permits. This is likely to include lower limits on existing monitoring parameters in discharge permits, as well as new analytical parameters of concern. The adoption of the new limits and parameters will result in additional monitoring expense and is fairly likely to require additional or alternative treatment technologies. A final rule is expected in the 2013-2014 timeframe.

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 available technology (BAT) for minimizing environmental impact including threat to aquatic life. As part of a settlement agreement EPA began development of new regulations to address impacts to aquatic life at CWISs. In March 2011 EPA released the second version of the draft rule which addresses existing facilities.

The draft rule would require all facilities withdrawing greater than 2 million gallons per day (MGD) to conduct baseline studies and address impingement. The two options for impingement reduction are to either install technology to reduce impingement mortality by 88% annually and no less than 69% in any given month, or reduce intake flow to less than 0.5 feet per second. The first option also requires performance monitoring for any technology installed. Facilities must also minimize entrapment.

The draft also would require entrainment reductions for all facilities greater than 2 MGD, however, baseline entrainment studies are only required for facilities with greater than

125 MGD withdrawals. Based on this information it would then be up to the entity that administrators the NPDES program to determine BTA.

Any new requirements could affect Coal Creek Station, Stanton Station and Elk River Station. Currently Stanton and Elk River stations have completed initial strategy analyses for compliance with the new rule and are conducting baseline and limited planning exercises based on available information. Stanton has also conducted some baseline impingement monitoring. A final rule is expected in early 2014.

SECTION L: Projected Demand for Service

Projected Demand. GRE's forecasted peak demands and energy requirements are provided in Exhibit 4. The forecast reflects the impact of the recent economic downturn.

Manner and Extent of Meeting Projected Demand. In addition to GRE's current generation capability, GRE has entered into a number of transactions of various types and durations with other utilities. These transactions help to utilize GRE's resources more effectively while deferring the need for new additions. GRE is a full transmission and market participant of the Midwest Independent Transmission System Operator (MISO), which operates short term energy and ancillary services markets that provide economic dispatch of generation and transmission congestion management over a broad region. In June 2009, MISO also began administering resource adequacy requirements to ensure that there is sufficient capacity available to meet expected demand requirements within its footprint.

Meeting summer peaks is GRE's primary resource capacity concern. GRE added combustion turbines In 2001, 2002, 2007, and 2009.

GRE is aggressively pursuing additional opportunities for conservation, energy efficiency, and load management. GRE, in concert with its member systems, will strive to meet the 1.5% Energy Efficiency Policy Goal established by Minnesota statute.

Given the current forecast of future demand and energy over the next 10 years GRE has no need for additional resources to meet those needs.

GRE intends to continue pursuing unique opportunities such as improvements to existing facilities, biomass and other non-wind renewables, combined heat and power projects, and energy storage (both utility-side and customer-side).

Load Centers. The service areas of GRE's 28 member cooperatives, shown in Figure 2, are located mainly in Minnesota and a small area in northwestern Wisconsin. Twenty of the member cooperatives are all-requirements customers. Eight member cooperatives purchase a fixed amount of capacity and associated energy from GRE and will meet their growth with purchases from other energy suppliers.

Fuel Sources and Transportation. Stanton Station originally burned lignite, but switched to Powder River Basin subbituminous coal in 2004. The coal is mined near Decker Montana and is transported to the plant via rail.

Coal Creek Station's generating units burn lignite that is mined at the adjacent Falkirk Mine and transported to the plant via trucks and conveyor belts.

The Elk River generating plant burns refuse-derived fuel (RDF). Municipal wastes are transported by truck to a processing plant near Elk River where it is converted to usable fuel. The RDF is trucked to the Elk River generating facility.

GRE has two combustion turbine peaking facilities (Pleasant Valley and Lakefield Junction) located in southern Minnesota. These facilities use natural gas as their primary fuel which is transported by pipelines and fuel oil as a back-up fuel, which is transported by truck.

GRE has six combustion turbine peaking facilities (Cambridge I, Cambridge II, Rock Lake, Maple Lake, St. Bonifacius, and Elk River Peaking Station) located in central Minnesota. Cambridge II is fueled with natural gas. The Elk River Peaking Station can use either natural gas or fuel oil. The remaining facilities use fuel oil, which is transported by truck. St. Bonifacius is also connected to a fuel oil pipeline, which adds a fuel transport option.

Figure 1 – GRE's Members and Their Service Areas

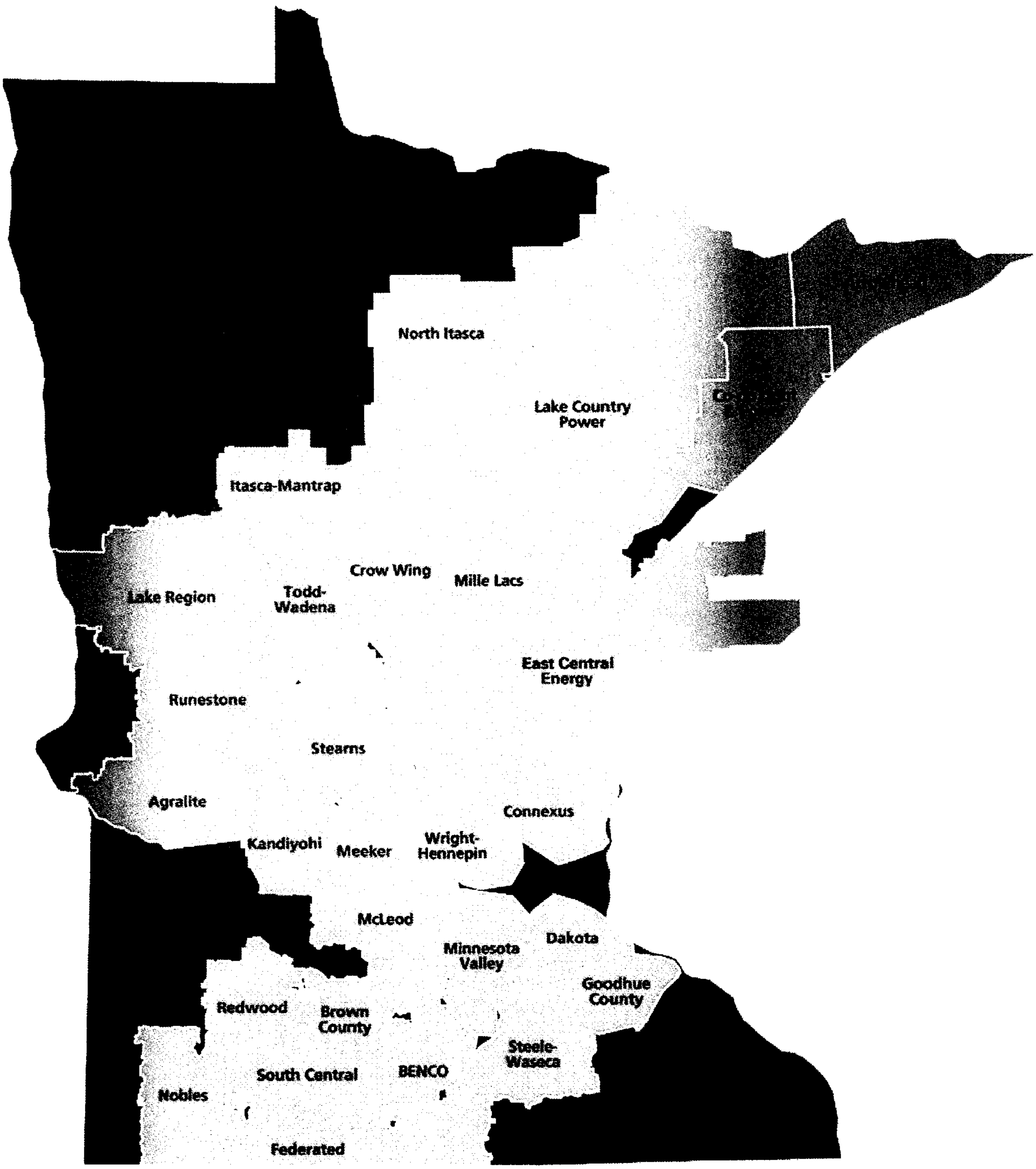

Exhibit 1

U.S. Department of Energy
Energy Information Administration Form EIA-767

(Forms supplied upon request.)

Exhibit 2

Federal Energy Regulatory Commission Form 715

(Forms supplied upon request.)

Exhibit 3

Location of the Coal Creek Station

Water Intake Pipeline

(Map supplied upon request.)

Exhibit 4

Projected Load Growth

and

Forecast Methodology

Demand and Energy Forecasts

The forecasts shown below are a combination of a 5-year monthly forecast (2011-2015) and 2010 Long-Range Load Forecast (2016-2040) for our twenty all requirement members plus fixed amounts of capacity and energy to serve eight "fixed" members who purchase their load growth from alternate suppliers. These forecasts were developed in 2010. In addition to GRE's member system's demand and energy, it includes transmission system losses and GRE's own use.

The following figures show GRE's 50% probability energy and demand forecasts compared with recent history.

Figure 4A - GRE Energy Forecast

Figure 4B - GRE Demand Forecasts

Exhibit 5

GRE

North Dakota Transmission Map

(Map supplied upon request.)