Great River Energy's

North Dakota Ten-Year Plan Report

2010-2019

Submitted to
The North Dakota Public Service Commission

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

July 1, 2010

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INTRODUCTION

This report was prepared in accordance with the North Dakota Public Service Commission's 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. Since submitting its 2009 report:

- The capacity of Coal Creek Unit 2 has been increased by about 30 MW as a result of replacing turbine rotors and completing various efficiency improvement projects. These projects were completed for Unit 2 during its major outage in 2010.
- GRE completed constructing lignite drying units for Coal Creek Station Units 1 and 2. When the driers are operating, sulfur dioxide emissions decrease by approximately 48 percent, mercury by 35%, NOx by 32% as well as reduced CO2 and particulate emissions due to the reduced flue gas volume and dryer density separation. The dryers entered commercial operation in the 4^{th} quarter of 2009. GRE is marketing the dryer technology for use in other power plants. The dryer has and continues to meet expectations.
- GRE completed negotiations to purchase the output of two existing wind projects. One of the projects, Ashtabula II Wind Energy Center, is located in Griggs and Steele counties in North Dakota. GRE will begin purchasing the output from a 51 MW portion of the project later in 2010. GRE also will be purchasing the output from the Endeavor wind project, which is located in Osceola County, Iowa. Endeavor is a 100 MW project and GRE will begin purchasing its output in 2011.
- GRE has completed construction of a 175 MW, dual fuel (natural gas and oil), simple cycle combustion turbine adjacent to its Elk River, Minnesota facility and placed it in service in July 2009.

GRE 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. The ratings are Net Dependable Capacity as determined in the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS).

Table 1- GRE's Existing Energy Conversion Facilities

Unit Name	Summer Capacity (MW)
Coal Creek Station 1 (Coal)	543.3
Coal Creek Station 2 (Coal)	552.4
Stanton Station (Coal)	174.7
Genoa 3 (share of coal plant)	169.9
Elk River Station 1-3 (RDF)	24.8
Chandler Wind *	6.0
Christoffer Wind *	5.7
McNeilus Wind *	5.7
Trimont Wind *	100.0
Prairie Star Wind *	100.0
Elm Creek Wind *	99.0
Pleasant Valley Station (Peaking)	410.7
Lakefield Junction (Peaking)	498.1
Cambridge CT (Peaking)	23.2
Cambridge CT2 (Peaking)	154.9
Maple Lake CT (Peaking)	18.1
Rock Lake CT (Peaking)	19.2
St. Bonifacius CT (Peaking)	56.5
Elk River CT (Peaking)	175.0
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 rating 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 planned for completion in October 2010 with commercial operation in January 2012. 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 is investigating a number of options to meet 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

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 ten years, GRE is investigating a number of options to meet its future needs, including additional renewable energy resources to comply with Minnesota's Renewable Energy Standard and additional natural gas peaking and combined cycle generation. GRE has also identified a need for additional baseload energy beyond 2020 and is investigating alternatives to meet that need, including coal with carbon capture, nuclear, and hydro.

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 facility 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 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 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
- Minnesota:
  - Certificate of Need
  - 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 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.

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)

MISO evaluation of the remaining capacity from Spiritwood may require transmission additions, Studies to date have identified the potential need to rebuild an existing Ottertail 115 kV line in the Jamestown area. More study work is pending.

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.midwestiso.org.* MISO's transmission expansion plans (MTEP-0909 being the most-recent approved plan) are also available at that web site under the "Planning" tab.
- The Midwest Reliability Organization (MRO), an 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. GRE remains a transmission-using member of MAPP, but has served notice to withdraw in 2011. Further information about MAPP is available on-line at *www.mapp.org*.

- MISO conducts Subregional Planning Meetings (SPMs) three 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 14 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) and the Distributed Renewable Generation (DRG) study 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 and are pursuing route permits.
    - The **Hampton – Rochester - La Crosse 345 kV Project** is an approximately 150-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 **Twin Cities - Fargo 345 kV Project** is an approximately 250-mile, 345 kV transmission line between Monticello, St. Cloud, Alexandria and Fargo, North Dakota. The project has been divided into two route permit applications before the MN Public Utilities Commission. The first application 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 application is for an approximately 230-mile transmission line between the new Quarry substation near St. Cloud, Minnesota and a new Bison substation west of Fargo, North Dakota.
    - The **Brookings County – Hampton 345 kV Projec**t 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 **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.

CapX2020 and the MTO group are also 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 are being 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. The CapX2020 utilities actively participate in those studies. The studies listed below are 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 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 Office of Energy Security website.
- Vision2030 Study: This purpose of the study is to develop a view of the Upper Midwest energy market in the year 2030. The study will be used to develop a transmission plan which meets Upper Midwest customer needs. The study is expected to be completed in September 2010. The study is being developed by CapX2020.

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 is a participant in the Regional Generation Outlet Study (RGOS) led by MISO. The goal of the RGOS study is to develop transmission projects that will facilitate the state renewable energy mandates in the Midwest ISO footprint. The process used to meet this goal consists of detailed transmission design analysis to determine a transmission system that meets the RGOS study objectives. This analysis will utilize the zone development and selection work from the RGOS I and II initiatives. It will also utilize the indicative transmission development as well as the detailed transmission analysis already performed within the RGOS I work efforts. The RGOS study will deliver one plan to Appendix B of the Midwest ISO Transmission Expansion Plan (MTEP) 2010 Report, as well as a RGOS report of results and findings. The selected plan will represent a least regrets portfolio solution based on detailed design development, sensitivity case analysis, and value metric application. Cost allocation is not part of the scope of the RGOS Phase I and II studies.

- The federal American Recovery and Reinvestment Act (ARRA) has directed the development of interconnection-based transmission plans. Twenty-four of the existing planning authorities in the Eastern Interconnection are working to create a collaborative planning process in an effort known as the Eastern Interconnection Planning Collaborative (EIPC). This EIPC process is intended to create interconnection-wide transmission plans using a bottoms up approach. Integral to the Collaborative approach is the roll-up and analysis of existing regionally developed plans. Two deliverables to the Department of Energy include:
    - June 2011 – 6-8 Future energy resource scenarios and 2020 roll up case,
    - June 2012 – Transmission portfolios that meet 3 select scenarios

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 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.

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. Since 2003, GRE has actively participated in the EPA's Coal Combustion Products Partnership (C2P2) to promote the benefits of coal combustion products – including fly ash.

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.

Re-using the ash 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, nearly 2.5 million cumulative tons of CO_2 have been avoided through GRE's ash re-use.

By re-using the 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 re-use.

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. Today nearly all the Stanton fly ash is used in the oil field industry.

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. US EPA is considering options for regulating the disposal of all CCPs. One of their options is to regulate these materials as 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 adverse 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.

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 operating in December 2009. GRE is pursuing marketing the dryer technology for use in other power plants; nearly 50% of the global coal is low-rank.

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

Regional Haze. The U.S. Environmental Protection Agency (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, to reach "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, 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 will 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 effective compliance date of 2023 for any applicable control requirements.

National Ambient Air Quality Standards. The U.S. Environmental Protection Agency (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.

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.

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. One could expect a MACT rule to require approximately 90 percent mercury removal. EPA is currently gathering additional HAP emission information to better characterize the electric generating industry. EPA is expected to set limits based on the best performing 12% of units, and has latitude to subcategorize units, based on fuel, boiler type and/or emission controls. It remains to be seen how EPA will decide to subcategorize. EPA is under court order to propose MACT rules in early 2011. 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. Since GRE has conducted significant mercury reduction research at our plants, 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.

Greenhouse Gas Emissions. There is currently no state or federal regulation of CO_2 emissions. Nevertheless, GRE continues to evaluate its greenhouse gas emissions and assess opportunities for carbon reduction.

GRE actively participated in Minnesota’s Climate Change Advisory Group to develop a state action plan. GRE is involved with the Midwest Governors Association’s Energy Initiatives and has a seat on the Energy Efficiency Advisory Group. GRE is also active in trying to shape federal legislation of GHG emissions in concert with the National Rural Electric Cooperative Association (NRECA). GRE is a partner in the U.S. Environmental

Protection Agency's SF_6 Emission Reduction Partnership for Electric Power Systems program whereby GRE established and reports progress towards annual SF_6 (sulfur hexafluoride) reduction goals. 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. GRE has been tracking and voluntarily reporting its greenhouse gas emissions since 1995. GRE is a Founding Reporter of The Climate Registry. 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 the U.S. Environmental Protection Agency (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 impaired waters list, 303(d) list, includes lakes, streams and rivers with impairments for use as drinking water, fishable waters, swimming, industrial use and/or irrigation.

Once the 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. 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.

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. The new regulations consist of three phases. Phase I (released December 18, 2001) applies to new facilities with a CWIS. Phase II became final July 9, 2004 and applies to existing utility power plants that have an NPDES permit and a CWIS with a design capacity of greater than 50 million gallons per day (mgd). Phase III was proposed November 24, 2004 and applies to non-utility CWISs greater than 50 mgd. The Phase II rule was remanded back to EPA by the 2nd Circuit Court in early 2008. Currently, EPA is rewriting the rule to address the Court findings.

Phase I of the rule applies to any new facilities with an NPDES permit and a CWIS design of greater than two mgd. The rule provides a two-track decision making process of either installing highly protective intake technologies or conducting a site-specific analysis of the proposed CWIS's impacts to aquatic life. The study must demonstrate the proposed CWIS will be adequately protective of aquatic life. Any new projects planning to utilize surface water for cooling purposes will have to address Phase I of the rule.

Phase II of the rule is for existing utility CWISs based on the parameters mentioned above. The previous Phase II rule applied performance standards based on the size of the intake, the amount of water it withdraws and the source water body type. With the Phase II portion currently being rewritten by EPA, specific performance standards and what constitutes "best available technology" are unknown at this time.

Any new requirements will affect Stanton Station and Elk River Station. Currently both stations have completed initial strategy analyses for compliance with the new rule and are conducting baseline and limited planning exercises based on available information.

SECTION L: Projected Demand for Service

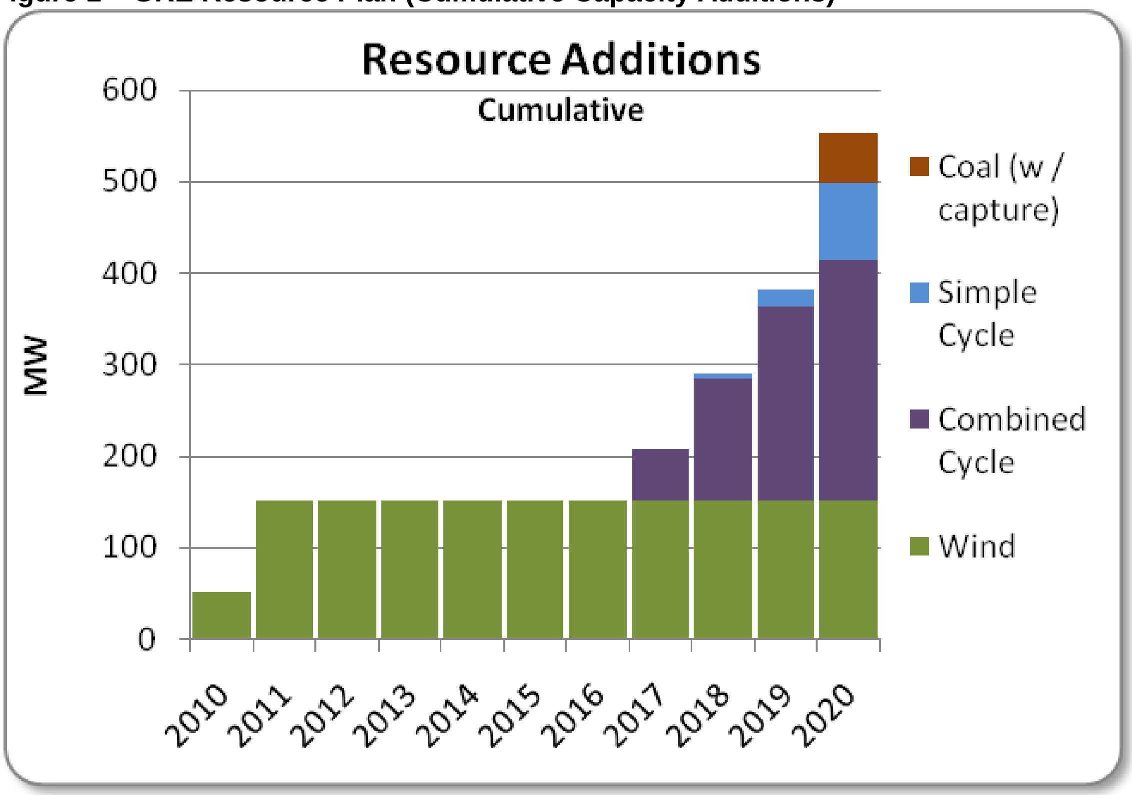
Projected Demand. GRE's forecasted peak demands and energy requirements are provided in Exhibit 4. The plans shown below were prepared in 2008 prior to the current economic slowdown. In the near-term, GRE is experiencing slower growth. This will delay GRE's need for new resources, but will not likely affect the types of resources needed. Significant effort is underway to incorporate all economic changes in a new long-range load forecast. This revised forecast will be included in the next filing of GRE's Ten-Year plan.

Manner and Extent of Meeting Projected Demand. In addition to GRE's current and planned 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, though it will be a difficult challenge. If the Energy Efficiency Policy Goal is met, GRE forecasts needing the following additional resources, identified generically:

Figure 1 – GRE Resource Plan (Cumulative Capacity Additions)



In the next five years, the only resource additions indicated are wind. This is a proxy for all types of renewable resources. GRE is well ahead of Minnesota's renewable energy standard and does not need additional renewable resources for compliance until at least 2020.

GRE will need additional natural gas-fired generation around 2017. No commitment decision is necessary now since such resources have relatively short lead times, although we will continue to develop options. The specific timing and types of these additions (simple cycle or combined cycle) will depend on market conditions, fuel costs, and the pace of demand and energy growth.

GRE will need additional low/no carbon baseload resources sometime after 2020. Although the chart above shows coal with CO_2 capture as meeting this need, there is enough uncertainty about the costs and future availability of resources such as nuclear and advanced coal with carbon capture that there is no clear choice at this time. Since any of these alternatives involve significant challenges and long lead times, GRE is conducting early work to develop options.

In addition to the above resources, 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 purchase a fixed amount of capacity and associated energy from GRE and will meet their growth with purchases from other energy suppliers. Resources to serve their growth are not included in the resource additions chart above.

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. 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 2 – GRE's Members and Their Service Areas

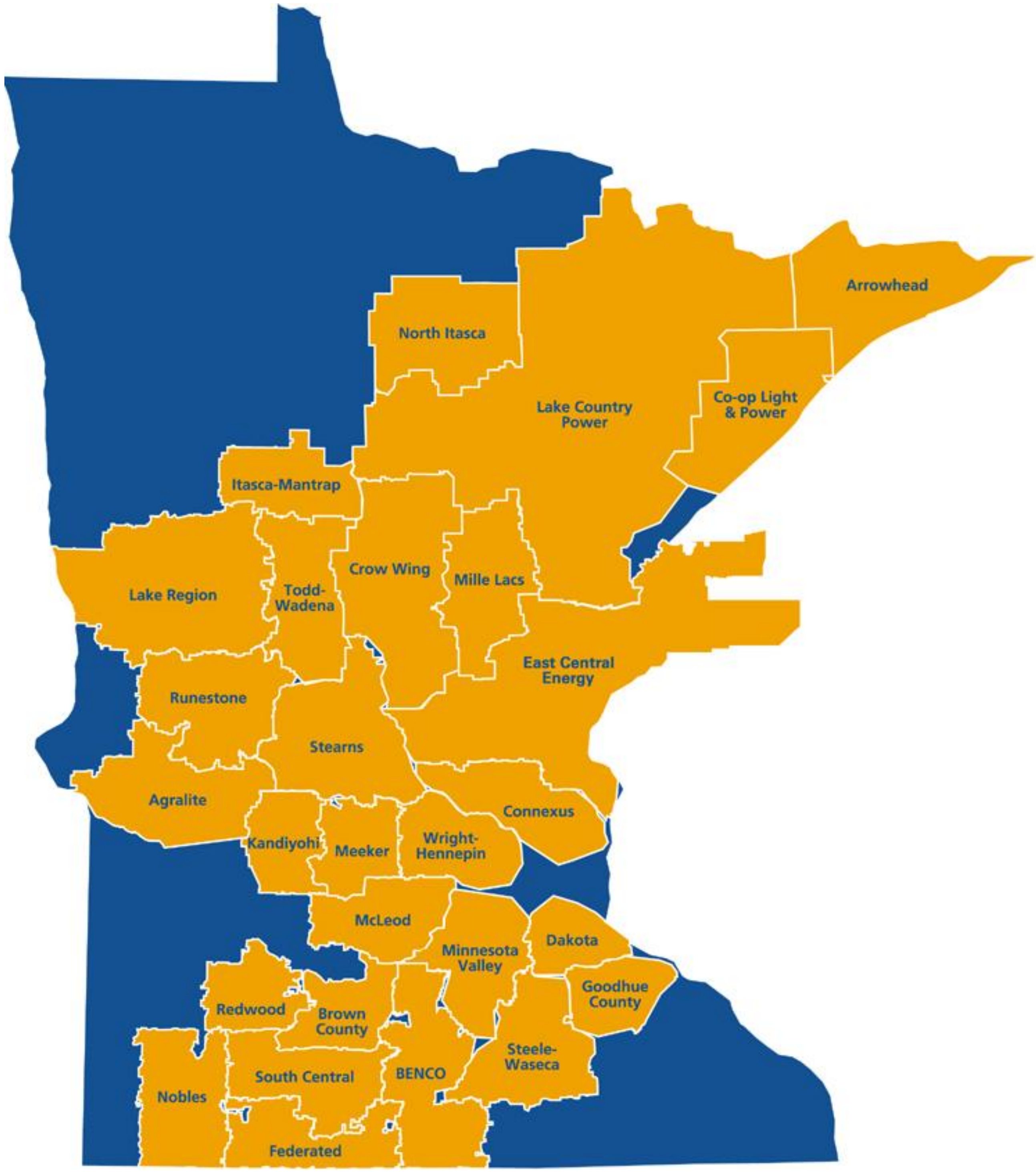


Exhibit 1

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 is the 2008 Long-Range Load Forecast for our twenty all-requirements members plus fixed amounts of capacity and energy to serve eight “fixed” members who purchase their load growth from alternate suppliers. This forecast was developed in 2008 and completed in January 2009. In addition to GRE’s member systems’ demand and energy, it includes transmission system losses and GRE’s own use.

This forecast reflects a slowdown in housing starts but not necessarily the broader effects of the current recession.

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

Figure 4A - GRE Energy Forecast

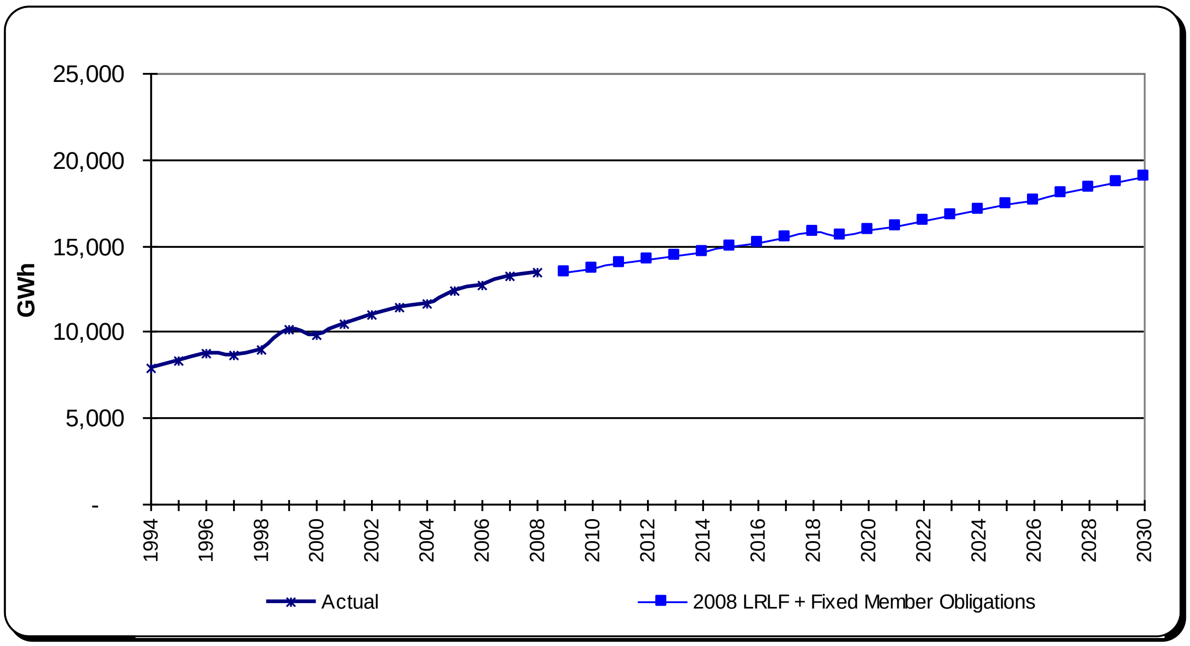


Figure 4B - GRE Demand Forecasts

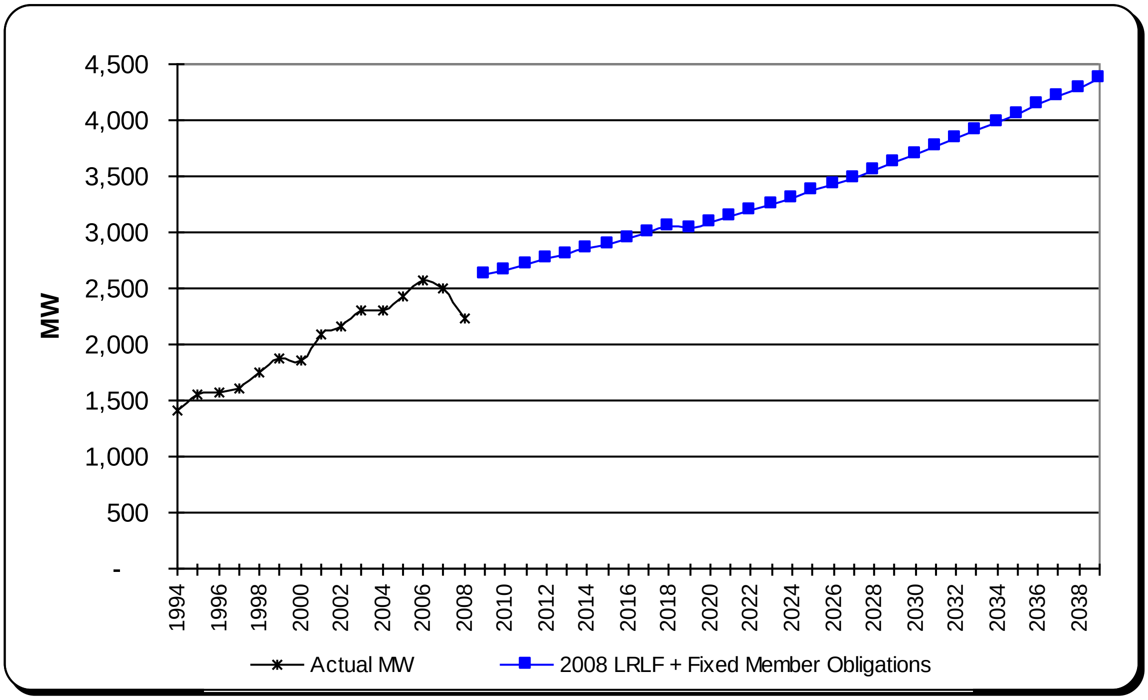


Exhibit 5

GRE

North Dakota Transmission Map

(Map supplied upon request.)