Certificate of Need Application

Cambridge Station

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Public Version

Trade Secret Information Excluded

February 28, 2005

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EXECUTIVE SUMMARY

Great River Energy (GRE), headquartered in Elk River, Minnesota, is applying for a Certificate of Need to construct a project consisting of a single simple-cycle combustion turbine at the site of its existing Cambridge Peaking Plant located in Cambridge Township, Isanti County, Minnesota (the project). The estimated accredited summer output of the project will be approximately 170 megawatts (MW). The project is needed for GRE to provide capacity and energy to its member cooperatives starting in summer 2007. GRE is projecting a deficit of approximately 136 MW in summer 2007 without the project.

GRE is a generation and transmission cooperative based in Elk River, Minnesota. GRE provides electrical energy and related services to 28 member cooperatives. Those distribution cooperatives, in turn, supply electricity and related services to more than 580,000 residential, commercial and industrial customers in Minnesota and Wisconsin (or a population of 1.5 million people). GRE's approximately 2,500-megawatt generation system is composed of a mix of baseload and peaking power plants, including coal-fired, refuse-derived fuel, natural gas and oil plants, as well as wind generation.

GRE's summer demand is projected to increase an average of approximately 100 MW per year, which translates into an average annual rate of 3.2 percent over the forecast period. In contrast, energy usage is forecasted to grow at a rate of 2.4 percent. By summer 2007, a capacity deficit of 136 MW is projected.

The project is being developed to meet GRE's existing and future peaking resource needs. Peaking generation facilities operate for relatively few hours per year. Cambridge Station is expected to be operated typically during times of peak electrical demand, which generally occur during periods of very high or very low temperatures. A utility's peaking resources often represent as much as 40 percent of its capacity requirement but provides less than five percent of the total energy requirements. As a result, this favors low capital cost technologies because of the severely reduced number of kilowatt-hours (kWh) over which to spread the fixed costs.

GRE cannot satisfy its needs through its existing facilities. GRE has recently upgraded several of its existing generating facilities. Further upgrades would not meet the peaking needs identified in this filing.

The project is the appropriate type of resource to cover peak demands and a small portion of energy requirements. GRE evaluated the proposed project against a fuel-oil fired simple-cycle combustion turbine and an ethanol-fired combustion turbine. The following other resource opportunities were evaluated as alternatives to the project:

- renewable resources including wind, biomass, hydro, and solar
- conservation programs
- distributed generation
- emerging technologies including fuel cells, micro turbines, and energy storage

All of these opportunities were either better suited for base load application, could not be procured and installed in time to GRE's expected capacity deficit in 2007, do not have appropriate operating characteristics to meet GRE's current needs, or are not commercially available.

The project will have minimal environmental impacts. The project utilizes a clean fuel and a combustion technology that have minimal impacts on the surrounding environment. The project is being sited to minimize the construction of the gas pipeline and transmission lines needed to serve the project.

GRE has a long history of cost-effective conservation programs, which have delayed the need for peaking capacity projects like this. In 2004, GRE had approximately 345 MW of its peak load controlled through demand-side management programs. Cost-effective programs will be continued but are expected to diminish peak demands in the immediate future by an amount insufficient to eliminate the need for the project.

The rural and suburban service territory of GRE's member cooperatives will benefit from the project. The project will help GRE's member cooperatives continue to supply competitively priced power to their customers. Low cost electricity is an important component in supporting stable economic growth in the region.

The proposed GRE self-build alternative has the lowest overall costs and best meets GRE's needs as determined through the solicitation and review of competitive peaking proposals. This application demonstrates that the project is needed, there are no reasonable alternatives to this project, and the project will provide significant benefits to society through maintaining a reliable and economic energy supply. Therefore, denial of this application would have an adverse effect upon the future adequacy and efficiency of energy supply to GRE and issuing a Certificate of Need for the project is fully supported by the record.

RULE COMPLIANCE

Minnesota Rules, Part	Information Required	Section and page of Application
	General Information	
	Applicant's complete name and address, telephone number, and standard industrial classification codes.	1.2
	Complete name, title, address, and telephone number of the official or agent to be contacted concerning the applicant's filing.	1.2
	Brief description of the nature of applicant's business and of the products that are manufactured, produced or processed, or the services rendered.	1.1
	Brief description of the proposed facility and its planned use.	1
7849.0200, subp. 4	Cover Letter	
	An application for a certificate of need must be accompanied by a cover letter signed by an authorized officer or agent of the applicant. The cover letter must specify the type of facility for which a certificate of need is requested.	Cover Letter
7849.0210, subp. 1	Filing Fee	
	Total fee for the application and the amount of the fee submitted with the application.	1.3
7849.0240, subp. 1	Need Summary	
	An application must contain a summary of the major factors that justify the need for the proposed facility.	2
7849.0240, subp. 2	Additional considerations	
(A)	Socially beneficial uses of the output of the facility, including its uses to protect or enhance environmental quality.	2.4

Minnesota Rules, Part	Information Required	Section and page of Application
(B)	Promotional activities that may have given rise to the demand for the facility.	2.4
(C)	Effects of the facility in inducing future development.	2.4
7849.0250	Description of Proposed LEGF and Alternatives	
7849.0250(A)	A description of the facility, including:	
(1)	Nominal generating capability of the facility, as well as a discussion of the effect of the economies of scale on the facility size and timing.	3
(2)	Description of the anticipated operating cycle, including the expected annual capacity factor.	3.7.1
(3)	Type of fuel used, including the reason for the choice of fuel, projection of the availability of this fuel type over the projected life of the facility, and alternate fuels, if any.	3.6
(4)	Anticipated heat rate of the facility.	3.7.2
(5)	Anticipated areas where the proposed facility could be located.	3.1
7849.0250(B)	Discussion of the alternatives to the facility.	
(1)	Purchased power.	4.4.1
(2)	Increased efficiency of existing facilities, including transmission lines.	4.4.2
(3)	New transmission lines.	4.4.3
(4)	New generating facilities of a different size or using a different energy source (fuel oil, natural gas, coal, nuclear fission, and the emergent technologies).	4.4.4
(5)	Any reasonably combinations of the alternatives listed in subitems (1) to (4).	4

Minnesota Rules, Part	Information Required	Section and page of Application
Minn. Stat. 216B.243, subd. 3a	Use of renewable resources. Applicant must demonstrate to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. "Renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.	4.2
7849.0250(C)	For the proposed facility and for each of the alternatives provided in response to item B that could provide electric power at the asserted level of need, a discussion of:	Table 4-3
(1)	Its capacity cost in current dollars per kilowatt.	
(2)	Its service life.	
(3)	Its estimated average annual availability	
(4)	Its fuel costs in current dollars per kilowatt hour	
(5)	Its variable operating and maintenance costs in current dollars per kilowatt hour	
(6)	Total cost in current dollars of a kilowatt hour provided by it	
(7)	Estimate of its effect on rates systemwide and in Minnesota, assuming a test year beginning with the proposed in-service date	
(8)	Its efficiency, expressed for a generating facility as the estimated heat rate, or expressed for a transmission facility as the estimated losses under projected maximum loading and under projected average loading in the length of the transmission line and at the terminals for substations	
(9)	Major assumptions made in providing the information in subitems (1) to (8), including projected escalation rates for fuel costs and operating and maintenance costs, as well as projected capacity factors	

Minnesota Rules, Part	Information Required	Section and page of Application
7849.0250(D)	Map (of appropriate scale) showing the applicant's system	1.1
7849.0250(E)	Such other information about the proposed facility and each alternative as may be relevant to determination of need	3, 4
7849.0260	LHVT and Alternatives	
	[Intentionally omitted because only 69 kV transmission lines will be added]	
7849.0270	Peak Demand and Annual Electrical Consumption Forecast	
7849.0270, subp. 1	Scope. Pertinent data concerning peak demand and annual electrical consumption within the applicant's service area and system, including but not limited to the data requested in subpart 2, item B below. When recorded data is not available, or when the applicant does not use the required data in preparing its own forecast, the applicant shall use an estimate and indicate in the forecast justification section in subparts 3 to 6 the procedures used in deriving the estimate. The application shall clearly indicate which data are historical and which are projected. It is expected that data provided by the applicant should be reasonable and internally consistent.	Appendix A
7849.0270, subp. 2	Content of forecast	
(A)	When applicant's service area includes areas other than Minnesota, annual electrical consumption by ultimate consumers within the applicant's Minnesota service area.	A – intro
(B)	For each of the following categories, estimates of the number of ultimate consumers within the applicant's system and annual electrical consumption by those consumers.	A-1
(1)	Farm, excluding irrigation and drainage pumping (for reporting purposes, any tract of land used primarily for agricultural purposes shall be considered farm land).	
(2)	Irrigation and drainage pumping.	

Minnesota Rules, Part	Information Required	Section and page of Application
(3)	Nonfarm residential (when electricity is supplied through a single meter for both residential and commercial uses, it shall be reported according to its principal use, and apartment buildings shall be reported as residential even if not separately metered).	
(4)	Commercial (this category shall include wholesale and retail trade; communication industries, public and private office buildings, banks, and dormitories; insurance, real estate and rental agencies; hotels and motels; personal business and auto repair services; medical and educational facilities; recreational, social, religious, and amusement facilities; governmental units, excluding military bases; warehouses other than manufacturer owned; electric, gas, water and water pumping, excluding water pumping for irrigation, and other utilities).	
(5)	Mining.	
(6)	Industrial (this category shall include all manufacturing industries, construction operations and petroleum refineries).	
(7)	Street and highway lighting.	
(8)	Electrified transportation (this category shall include energy supplied for the propulsion of vehicles, but shall not include energy supplied for office buildings, depots, signal lights or other associated facilities that shall be reported as commercial or industrial).	
(9)	Other (this category shall include municipal water pumping facilities, oil and gas pipeline pumping facilities, military camps and bases, and all other consumers not reported in subitems (1) to (8)).	
(10)	The sum of subitems (1) to (9).	
(C)	Estimate of the demand for power in the applicant's system at the time of annual system peak demand, including an estimated breakdown of the demand into the consumer categories listed in item B.	A.2.2 Table A-3

Minnesota Rules, Part	Information Required	Section and page of Application
(D)	Applicant's system peak demand by month.	A.2.3 Table A-4
(E)	Estimated annual revenue requirement per kilowatt hour for the system in current dollars.	A.2.4 Table A-5
(F)	Applicant's estimated average system weekday load factor by month; in other words, for each month, the estimated average of the individual load factors for each weekday in the month.	A.2.5 Table A-6
7849.0270, subp. 3	Forecast methodology. An applicant may use a forecast methodology of its own choosing, with due consideration given to cost, staffing requirements, and data availability. However, forecast data provided by the applicant is subject to tests of accuracy, reasonableness, and consistency. The applicant shall detail the forecast methodology employed to obtain the forecasts provided under subpart 2, including:	A.3
(A)	Overall methodological framework that is used.	A.3.2
(B)	Specific analytical techniques which are used, their purpose, and the components of the forecast to which they have been applied.	A.3.3 – A.3.7
(C)	Manner in which these specific techniques are related in producing the forecast.	A.3.3 – A.3.7
(D)	Where statistical techniques have been used:	
(1)	Purpose of the technique.	A.3.3 – A.3.7
(2)	Typical computations (e.g., computer printouts, formulas used), specifying variables and data.	A.3.8
(3)	Results of appropriate statistical tests.	A.3.8
(E)	Forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption, as well as a description of their derivation.	A.2.1
(F)	Brief analysis of the methodology used, including:	A.3.10

Minnesota Rules, Part	Information Required	Section and page of Application
(1)	Its strengths and weaknesses.	A.3.10.2
(2)	Its suitability to the system.	A.3.10.2
(3)	Cost considerations.	A.3.10.2
(4)	Data requirements.	A.3.10.2
(5)	Past accuracy.	A.3.10.3
(6)	Other factors considered significant by the applicant.	A.3.10.2
(G)	Explanation of discrepancies that appear between the forecasts presented in the application and the forecasts submitted under chapter 7610 or in the applicant's previous certificate of need proceedings.	A.3.10.3
7849.0270, subp. 4	Data base for forecasts.	
(A)	Complete list of all data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer's office).	A.3.9
(B)	Clear identification of any adjustments made to raw data in order to adapt them for use in forecasts, including:	A.3.9
(1)	Nature of the adjustment.	
(2)	Reason for the adjustment.	
(3)	Magnitude of the adjustment.	
	Applicant shall provide to the commission or the administrative law judge on demand copies of the data sets used in making the forecasts, including both raw and adjusted data, input and output data.	

Minnesota Rules, Part	Information Required	Section and page of Application
7849.0270, subp. 5	Assumptions and special information. The applicant shall discuss each essential assumption made in preparing the forecast, including the need for the assumption, the nature of the assumption, and the sensitivity of forecast results to variations in the essential assumptions. The applicant shall discuss the assumptions made regarding:	A.3.11
(A)	Availability of alternate sources of energy.	A.3.11
(B)	Expected conversion from other fuels to electricity or vice versa.	A.3.11
(C)	Future prices of electricity for customers in the applicant's system and the effect that such price changes will likely have on the applicant's system demand.	A.3.11
(D)	Data requested in subpart 2 that is not available historically or not generated by the applicant in preparing its own internal forecast.	A.2.3
(E)	Effect of energy conservation programs on long-term electrical demand.	A.2.5
(F)	Any other factor considered by the applicant in preparing the forecast.	A.3
7849.0270, subp. 6	Coordination of forecasts with other systems.	A.3.12
(A)	Description of the extent to which the applicant coordinates its load forecasts with those of other systems, such as neighboring systems and associate systems in a power pool or coordinating organization.	
(B)	Description of the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate load forecasts.	
7849.0280	System Capacity	

Minnesota Rules, Part	Information Required	Section and page of Application
	Applicant shall describe the ability of its existing system to meet the demand for electrical energy forecast in response to part 7849.0270 and the extent to which the proposed facility will increase this capability. In preparing this description, the applicant shall present the following information:	
7849.0280(A)	Brief discussion of power planning programs, including criteria, applied to the applicant's system and to the power pool or area within which the applicant's planning studies are based.	B.2
7849.0280(B)	Applicant's seasonal firm purchases and seasonal firm sales for each utility involved in each transaction for each of the forecast years.	Table B-3 Table B-4
7849.0280(C)	Applicant's seasonal participation purchases and seasonal participation sales for each utility involved in each transaction for each of the forecast years.	Table B-3 Table B-4
7849.280(D)	For the summer season and for the winter season corresponding to each forecast year, the load and generation capacity data requested in subitems (1) to (13), including the anticipated purchases, sales, capacity retirements, and capacity additions, except those that depend on certificates of need not yet issued by the commission:	History: Table B-1 Table B-2 Future Table B-3 Table B-4
(1)	Seasonal system demand.	
(2)	Annual system demand.	
(3)	Total seasonal firm purchases.	
(4)	Total seasonal firm sales.	
(5)	Seasonal adjusted net demand (subitem (1) minus subitem (3) plus subitem (4)).	
(6)	Annual adjusted net demand (subitem (2) minus subitem (3) plus subitem (4)).	
(7)	Net generating capacity.	

Minnesota Rules, Part	Information Required	Section and page of Application
(8)	Total participation purchases.	
(9)	Total participation sales.	
(10)	Adjusted net capability (subitem (7) plus subitem (8) minus subitem (9)).	
(11)	Net reserve capacity obligation.	
(12)	Total firm capacity obligation (subitem (5) plus subitem (11)).	
(13)	Surplus or deficit (-) capacity (subitem (10) minus subitem (12)).	
7849.0280(E)	For the summer season and for the winter season corresponding to each forecast year subsequent to the year of application, the load and generation capacity data requested in item D, subitems (1) to (13), including purchases, sales, and generating capability contingent on the proposed facility.	Summer: Table B-6 Winter: Table B-4
7849.0280(F)	For the summer season and for the winter season corresponding to each forecast year subsequent to the year of application, the load and generation capacity data requested in item D, subitems (1) to (13), including all projected purchases, sales, and generating capability.	Summer: Table B-6 Winter: Table B-4
7849.0280(G)	For each of the forecast years subsequent to the year of application, a list of proposed additions and retirements in net generating capability, including the probable date of application for any addition that is expected to require a certificate of need.	Table B-7
7849.0280(H)	For the previous calendar year, the current year, the first full calendar year before the proposed facility is expected to be in operation and the first full calendar year of operation of the proposed facility, a graph of monthly adjusted net demand and monthly adjusted net capability, as well as a plot on the same graph of the difference between the adjusted net capability and actual, planned, or estimated maintenance outages of generation and transmission facilities.	Figure B-1

Minnesota Rules, Part	Information Required	Section and page of Application
7849.0280(I)	Discussion of the appropriateness of and the method of determining system reserve margins, considering the probability of forced outages of generating units, deviation from load forecasts, scheduled maintenance outages of generation and transmission facilities, power exchange arrangements as they affect reserve requirements, and transfer capabilities.	B.6
7849.0290	Conservation Programs	
(A)	Name of the committee, department, or individual responsible for the applicant's energy conservation and efficiency programs, including load management.	C.1
(B)	List of the applicant's energy conservation and efficiency goals and objectives.	C.2
(C)	Description of the specific energy conservation and efficiency programs the applicant has considered, a list of those that have been implemented, and the reasons why the other programs have not been implemented.	C.3.1 C.3.2 C.5
(D)	Description of the major accomplishments that have been made by the applicant with respect to energy conservation and efficiency.	C.6 Table C-2 Table C-3
(E)	Description of the applicant's future plans through the forecast years with respect to energy conservation and efficiency.	C.4
(F)	Quantification of the manner by which these programs affect or help determine the forecast provided in response to part 7849.0270, subpart 2, a list of their total costs by program, and a discussion of their expected effects in reducing the need for new generation and transmission facilities.	C.7
7849.0300	Consequences of Delay	

Minnesota Rules, Part	Information Required	Section and page of Application
	Applicant shall present a discussion of anticipated consequences to its system, neighboring systems, and the power pool should the proposed facility be delayed one, two, and three years, or postponed indefinitely. This information must be provided for the following three levels of demand: the expected demand provided in response to part 7849.0270, subpart 2, and the upper and lower confidence levels provided in response to part 7849.0270, subpart 3, item E.	5
7849.0310	Environmental Information Required	
	Each applicant shall provide environmental data for the proposed facility and for each alternative considered in detail in response to part 7849.0250, item C or 7849.0260, item C. Information relating to construction and operation of each of these alternatives shall be provided as indicated in parts 7849.0320 to 7849.0340, to the extent that such information is reasonably available to the applicant and applicable to the particular alternative. Where appropriate, the applicant shall submit data for a range of possible facility designs. Major assumptions should be stated, and references should be cited where appropriate.	Submitted in conjunction with MEQB site permit application
7849.0320	Generating Facilities	
7849.0320(A)	Estimated range of land requirements for the facility with a discussion of assumptions on land requirements for water storage, cooling systems, and solid waste storage.	3.1
7849.0320(B)	Estimated amount of vehicular, rail, and barge traffic generated by construction and operation of the facility.	3.21
7849.0320(C)	For fossil-fueled facilities:	
(1)	Expected regional sources of fuel for the facility.	3.6.1
(2)	Typical fuel requirement (in tons per hour, gallons per hour, or thousands of cubic feet per hour) during operation at rated capacity and the expected annual fuel requirement at the expected capacity factor.	Table 3-1

Minnesota Rules, Part	Information Required	Section and page of Application
(3)	Expected rate of heat input for the facility in Btu per hour during operation at rated capacity.	Table 3-1
(4)	Typical range of the heat value of the fuel (in Btu per pound, Btu per gallon, or Btu per 1,000 cubic feet) and the typical average heat value of the fuel.	Table 3-1
(5)	Typical ranges of sulfur, ash, and moisture content of the fuel.	Table 3-1
7849.0320(D)	For fossil fueled facilities:	
(1)	Estimated range of trace element emissions and the maximum emissions of sulfur dioxide, nitrogen oxides, and particulates in pounds per hour during operation at rated capacity.	3.14.1
(2)	Estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from the stack of sulfur dioxide, nitrogen oxides, and particulates in micrograms per cubic meter during operation at rated capacity and assuming generalized worst-case meteorological conditions.	3.14.1
7849.0320(E)	Water use by the facility for alternate cooling systems, including:	
(1)	Estimated maximum use, including the groundwater pumping rate in gallons per minute and surface water appropriation in cubic feet per second.	Table 3-1
(2)	Estimated groundwater appropriation in million gallons per year.	Table 3-1
(3)	Annual consumption in acre-feet.	Table 3-1
7849.0320(F)	Potential sources and types of discharges to water attributable to operation of the facility.	3.14.1
7849.0320(G)	Radioactive releases, including:	

Minnesota Rules, Part	Information Required	Section and page of Application
(1)	For nuclear facilities, the typical types and amounts of radionuclides released by the facility in curies per year for alternate facility designs and levels of waste treatment.	NA
(2)	For fossil-fueled facilities, the estimated range of radioactivity released by the facility in curies per year.	3.14.1
7849.0320(H)	Potential types and quantities of solid wastes produced by the facility in tons per year at the expected capacity factor.	3.18
7849.0320(I)	Potential sources and types of audible noise attributable to operation of the facility.	3.20
7849.0320(J)	Estimated work force required for construction and operation of the facility.	3.8
7849.0320(K)	Minimum number and size of transmission facilities required to provide a reliable outlet for the generating facility.	Appendix D
7849.0330	Transmission Facilities	
	[Intentionally omitted.]	
7849.0340	The Alternative to No Facility	
	For each of the three levels of demand specified in part 7849.0300, the applicant shall provide the following information for the alternative of no facility:	
7849.0340(A)	Description of the expected operation of existing and committed generating and transmission facilities.	5
7849.0340(B)	Description of the changes in resource requirements and wastes produced by facilities discussed in response to item A, including:	5
(1)	Amount of land required.	
(2)	Induced traffic.	
(3)	Fuel requirements.	

Minnesota Rules, Part	Information Required	Section and page of Application
(4)	Airborne emissions.	
(5)	Water appropriation and consumption.	
(6)	Discharges to water.	
(7)	Reject heat.	
(8)	Radioactive releases.	
(9)	Solid waste production.	
(10)	Audible noise.	
(11)	Labor requirements.	
7849.0340(C)	Description of equipment and measures that may be used to reduce the environmental impact of the alternative of no facility.	5

1 INTRODUCTION

Great River Energy (GRE), a Minnesota cooperative corporation, is submitting this application to the Minnesota Public Utilities Commission (MPUC) to request approval of a 170-megawatt natural gas-fired power generation facility (Cambridge Station).

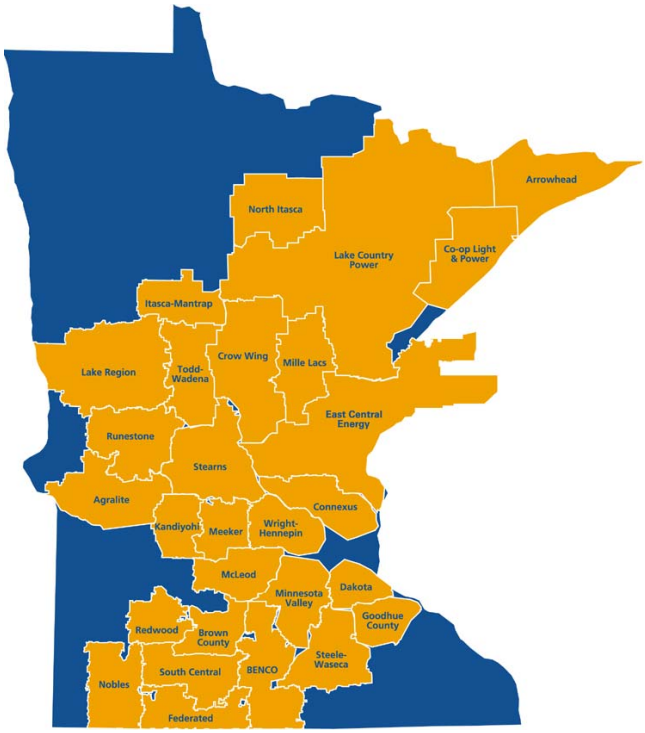
The project will consist of a simple-cycle combustion turbine. The turbine's fuel will be natural gas, chosen for its low air emissions and ready availability from a nearby pipeline. GRE is proposing to use an existing peaking plant site in Cambridge Township in Isanti County.

The project is being developed to meet GRE's existing and future peaking resource needs. Peaking generation facilities only operate a small number of hours per year (usually from 500-1,000 hours). Cambridge Station will typically be operated during times of peak electrical demand, which generally occur during periods of very high or very low temperatures and at times to support operation of the state's transmission grid. A utility's peaking resources often represent about 40 percent of its capacity requirement but provide less than 5 percent of the total energy requirements. As a result, this favors low capital cost technologies because of the severely reduced number of kilowatt-hours (kWh) over which to spread the fixed costs.

GRE has, to the extent reasonable, covered its recent growth in capacity needs through a combination of load management programs and capacity transactions with other members in the regional market. These strategies have deferred the need for making capital investments in new peaking facilities until now. The tightening capacity in the MAPP region leaves GRE vulnerable to capacity shortages and/or significant increases in the cost of purchasing power. The opening of the MISO markets on April 1 could help relieve this situation; however, the practical impacts of these market changes will not be known soon enough to rely upon for the avoidance of short-term capacity deficits.

The project described in this application is consistent with GRE's mission of providing reliable, competitively priced electricity to its member cooperatives. GRE's board of directors and its membership have approved the installation of this capacity addition.

1.1 Who Is Great River Energy?



GRE is a generation and transmission cooperative based in Elk River, Minnesota, formed by the merger of Cooperative Power (CP) and United Power Association (UPA) on January 1, 1999. Any historical references to GRE are intended to include CP and/or UPA to avoid confusing references to the predecessor organizations. GRE provides electrical energy and related services to 28 member cooperatives. Those distribution cooperatives, in turn, supply electricity and related services to more than 580,000 residential, commercial and industrial customers in Minnesota and Wisconsin (or a population of about 1.5 million people).

GRE's 2,500-megawatt generation system is composed of a mix of baseload and peaking power plants, including coal-fired, refuse-derived fuel, natural gas and oil plants, as well as wind generation. Over the past couple of years, major improvements have been made at the 1,079 MW baseload Coal Creek Station, located in central North Dakota, to make the plant more efficient, allowing those turbines to generate more electricity without burning additional coal.

GRE owns approximately 4,500 miles of transmission line, including the high voltage, 436 mile direct current, or DC, transmission line that runs from Coal Creek Station to Minnesota. GRE also owns or partially owns more than 100 transmission substations.

Great River Energy employs more than 700 people in Minnesota and North Dakota

1.2 Applicant Information

Mailing Address:	Great River Energy 17845 East Highway 10 P.O. Box 800 Elk River, MN 55330-0800
Telephone No:	(763) 441-3121
SIC Code:	4911
Project Contact:	Mr. Rick Lancaster Vice President – Corporate Services (763) 241-2428

1.3 Fees

The Certificate of Need fee is calculated based on the expected installed MAPP accredited summer capacity of 170 MW using the formula included in Minn. Rules pt. 7849.0210 Subp. 1. The total fee to be paid by Great River Energy will be $18,500[1].The payment schedule will follow the requirements of Minn. Rules pt.7849.0210 Subp. 2, with four equal installments of $4,625 as follows: with the application; and within 45, 90 and 135 days of the application's submittal.

[1] Minn. Rules pt. 7849.0210 requires a fee equal to $10,000 plus $50 times the 170 MW capacity of the facilities. The rule also requires 25 percent of the fee to accompany the application, with three equal payments of the balance due within 45, 90 and 135 days of the submission of the application.

2 CAPACITY AND ENERGY NEED SUMMARY

This project is needed to meet the needs of GRE's member cooperatives for capacity and energy starting in the summer of 2007. Without the project, GRE is projecting that peak demand will exceed existing capacity by approximately 142 MW in summer of 2007.

2.1 GRE's Capacity Needs

GRE is a summer peaking system. The growth in summer demand drives GRE's needs for the proposed project. GRE expects to be capacity deficit beginning in the summer of 2007. GRE has adequate capacity to cover its winter peak in the near to medium term.

The forecast data presented in this filing is derived from GRE's 2002 Long Range Load Forecast (2002 load forecast). This is the most recent forecast that has been fully approved by the Rural Utilities Service (RUS). RUS rules require that only RUS-approved forecasts be used for planning purposes. This forecast was also accepted by the Minnesota Public Utilities Commission (MPUC) in GRE's 2003 Integrated Resource Plan (2003 IRP) filing. GRE is constantly studying its demand and other aspects of the forecast and is currently in the process of finalizing the 2004 Long Range Load Forecast (2004 load forecast). Although the new forecast numbers will not be official until approved by GRE's board of directors and the RUS, GRE will give an indication of the preliminary results from the 2004 forecast, where relevant.

The methodology used to develop the forecast and other forecast details required by Minnesota Rules 7849.0270 are provided in Appendix B.

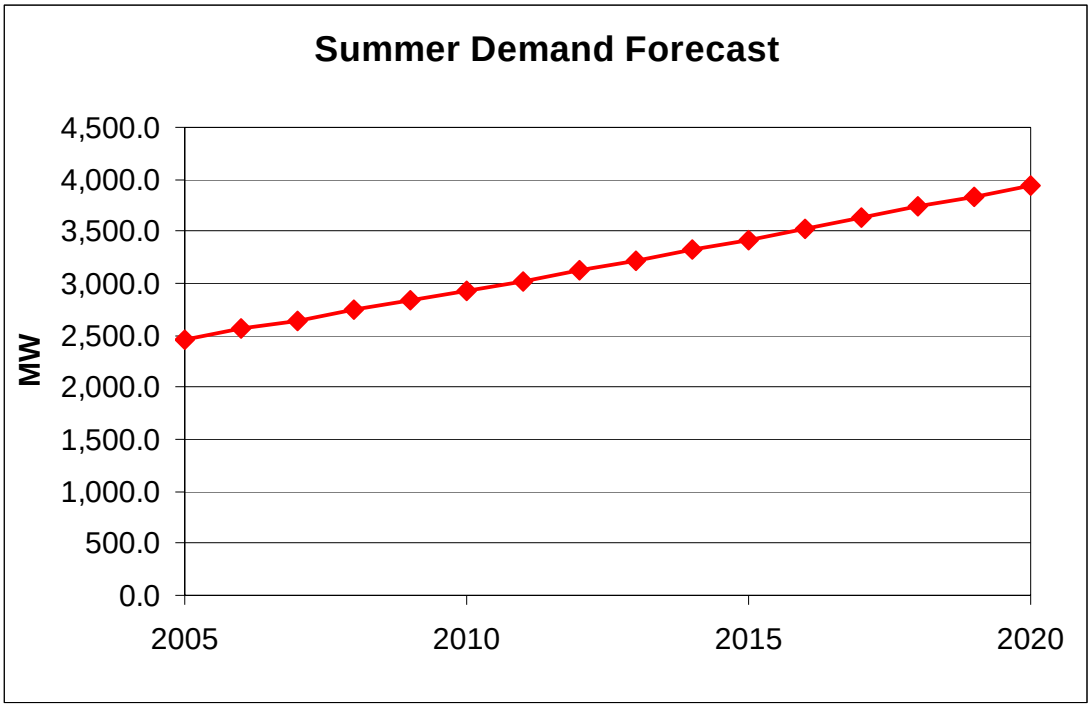
2.1.1 GRE's Capacity Forecast

In developing its long-range forecast, GRE analyzes multiple scenarios, varying assumptions regarding weather and macroeconomics. One of the scenarios is a base-case demand forecast. This base case represents projected demand in "average" conditions and is expected to cover actual demand 50 percent of the time. However, with the base case, actual demand will also exceed the forecast 50 percent of the time. GRE has determined that it would be too risky to use the base case for planning purposes. Because of the critical nature of meeting its members' demand for electricity, GRE must have a high degree of certainty that its resources will meet its needs. Thus, for planning

purposes, GRE utilizes a scenario estimated to capture peak demand 90 percent of the time. This is much more appropriate for GRE's system. In particular, GRE's demand is very weather sensitive. It is important for GRE to plan sufficiently to meet the potential high demand that could arise during hot summer weather. GRE is confident that it can best meet its members' needs by utilizing the higher probability demand scenario.

GRE's summer demand, using the high probability demand assumption, is expected to increase at an average of approximately 100 MW per year, which translates into an average annual rate of 3.2 percent over the forecast period. Figure 2-1 illustrates the demand forecast based on 2002 load forecast, using the high probability demand scenario. Figure 2-1 does not include GRE's reserve requirement.

Figure 2-1 - GRE's Peak Demand Growth Summary



As mentioned earlier, these forecast numbers come from GRE's 2002 load forecast. Since that time, GRE has continued to study and update its forecast. Preliminary results of its 2004 load forecast reinforce this growth rate and show peak demands significantly higher than those in the 2002 load forecast. GRE will present its updated forecast information, once it has been finalized

and internally approved, in its next Integrated Resource Plan filing, which is scheduled to be made on or before July 1, 2005.

2.1.2 GRE's Available Resources

Table 2-1 below summarizes GRE's available resources in the near term, as rated for summer operations. The resource numbers are based on 2005 accredited levels. Upgrades and changes to generator ratings could change the actual 2007 numbers by a small amount.

Table 2-1 - GRE's Near Term Summer Load and Available Resources

Capacity Source	Estimated 2007 Accredited Summer Capacity and Firm Load (MW)
GRE Accredited Sources	
Cambridge CT	19.4
Maple Lake CT	19.1
Rock Lake CT	19.3
St. Bonifacius CT	50.0
Elk River Unit 1	10.5
Elk River Unit 2	10.5
Elk River Unit 3	17.9
Stanton Station [1]	187.7
Coal Creek Station Unit 1	551.0
Coal Creek Station Unit 2	561.0
Coal Creek Station Diesel Generator	2.0
Pleasant Valley Station Unit 11	153.6
Pleasant Valley Station Unit 12	150.9
Pleasant Valley Station Unit 13	122.8
Lakefield Junction Stations Unit 1	85.8
Lakefield Junction Stations Unit 2	85.4
Lakefield Junction Stations Unit 3	85.7
Lakefield Junction Stations Unit 4	85.0
Lakefield Junction Stations Unit 5	85.9
Lakefield Junction Stations Unit 6	85.0
Lakefield Junction Stations Diesel Generator	2.0
Chandler Hills Wind Farm	0.1
Total Accredited Capacity	2,390.6
GRE Total Accredited Purchases	782.7
GRE Total Accredited Sales	(274.9)
GRE's Net Capability to Serve Load	2,898.4
2007 Load Forecast	(2,644.5)
2007 Load Forecast (including 15% MAPP reserves)	(3,041.2)
2007 Capacity Deficit	(142.8)

1. Includes the capacity of the diesel back up generator.

In general, GRE has three types of existing resources: baseload plants, peaking plants and long-term purchases (which largely fulfill the role of intermediate resources). In addition, GRE supplements its own resources with short-term market purchases.

GRE's existing baseload resources include Stanton Station, Coal Creek Station and Elk River Station. Both Stanton and Coal Creek Stations are coal-fired plants located in central North Dakota. Elk River Station is a refuse-derived fuel plant in Elk River, Minnesota. In addition, GRE has a life-of-the-plant contract with Dairyland Power Cooperative to purchase half the output of the Genoa 3 coal-fired plant. Some of GRE's long-term purchases also have a baseload type pricing structure.

GRE also has significant peaking resources. These include the approximately 1000 MW that have been recently added through the Pleasant Valley Station and Lakefield Junction Station, as well as four smaller oil-fired combustion turbines.

An important aspect of GRE's resources not reflected in the above figure is GRE's significant level of demand-side savings. GRE estimates that demand-side programs replaced the need for 345 MW of accredited capacity (factoring in the 15 percent MAPP reserve requirement) during its 2004 summer peak.

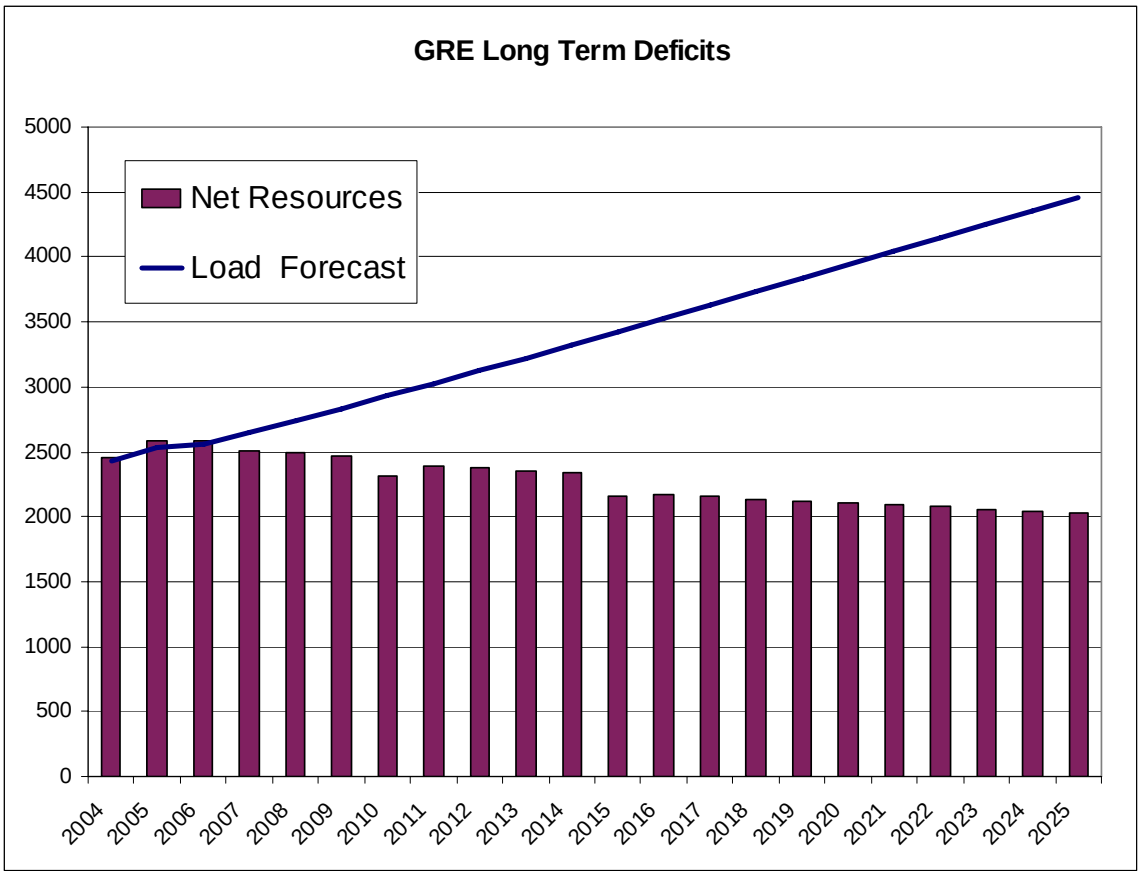
GRE's long-term purchases are listed in Appendix B.

Further, GRE's entire portfolio of generating resources and long-term contracts is supplemented with prudent use of short-term market power purchases. GRE uses short-term energy purchases any time the market energy price is lower than the incremental price of the next generating unit or power purchase contract that would otherwise have been used to serve its load. In the past, GRE has also made short-term capacity purchases to fulfill its final capacity needs once a refined short-term forecast is determined. However, the regional capacity market has tightened and GRE's market research indicates that the market could not economically meet its current need for peaking capacity. The impending start of the MISO markets could provide access to a wider market but cannot be relied upon as it is yet untested. Further, the MISO market is designed around energy transactions, not capacity.

2.1.3 Overview of GRE's Capacity Forecast

Figure 2-2 summarizes the GRE capacity situation without the project. The line labeled "Load Forecast" is the load forecast for GRE from the 2002 load forecast. The columns below represent the net of all GRE owned resources, purchases and sales, and GRE's reserve obligation. The chart represents the summer season situation with all resources represented using the MAPP - accredited capacity for the summer season.

Figure 2-2 - GRE Net Resources vs. Load Forecast



As the figure illustrates, GRE begins experiencing capacity deficits in 2007. (Note: the load forecast does not include reserve requirements, but instead the capacity numbers are reduced by the appropriate amount to cover reserves.) The proposed project is sufficient to bridge the entire gap in 2007 and a large portion of the deficit in 2008. Clearly GRE's needs far exceed this single project. GRE's internal resource planning is an ongoing and iterative process. GRE expects to present a refined action plan for meeting the remainder of its needs in the planning horizon in its next Integrated Resource Plan.

Table 2-2 – Near Term Capacity Surplus/Deficit

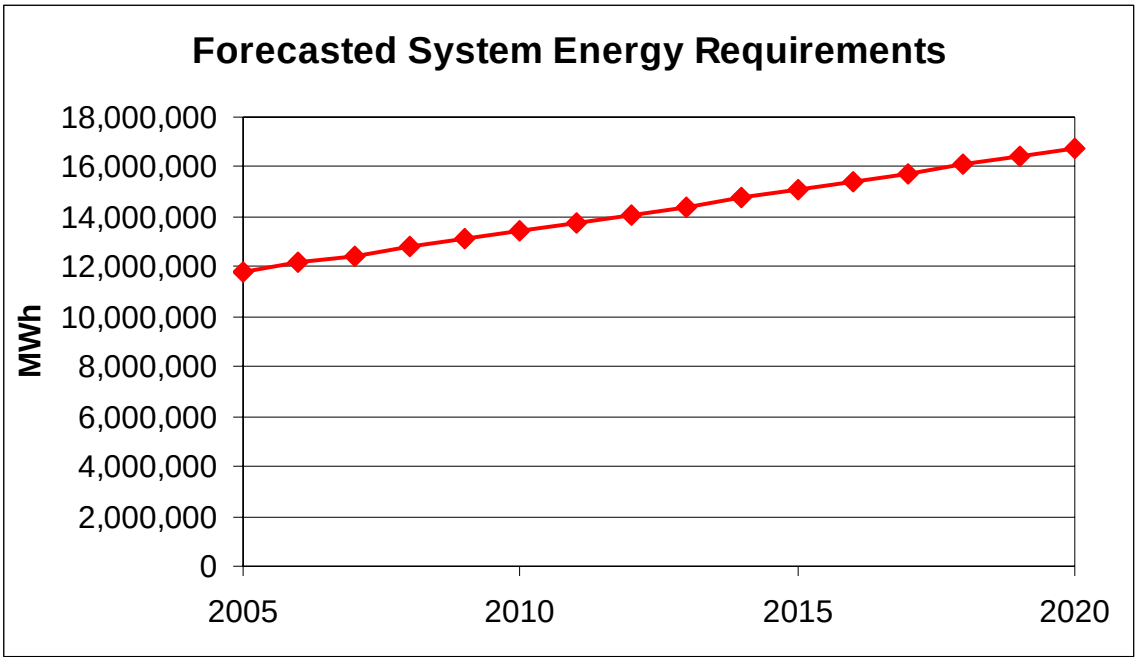
Near Term Capacity Surplus/Deficit		
Year	Without Project (MW)	With Project (MW)
2005	52.2	52.2
2006	20.8	20.8
2007	-142.8	27.2
2008	-253.1	-83.1
2009	-361.8	-191.8

2.2 GRE's Energy Needs

2.2.1 GRE's Energy Forecast

Figure 2-3 shows GRE's forecast for energy growth.

Figure 2-3 – GRE's Forecasted Energy Requirements



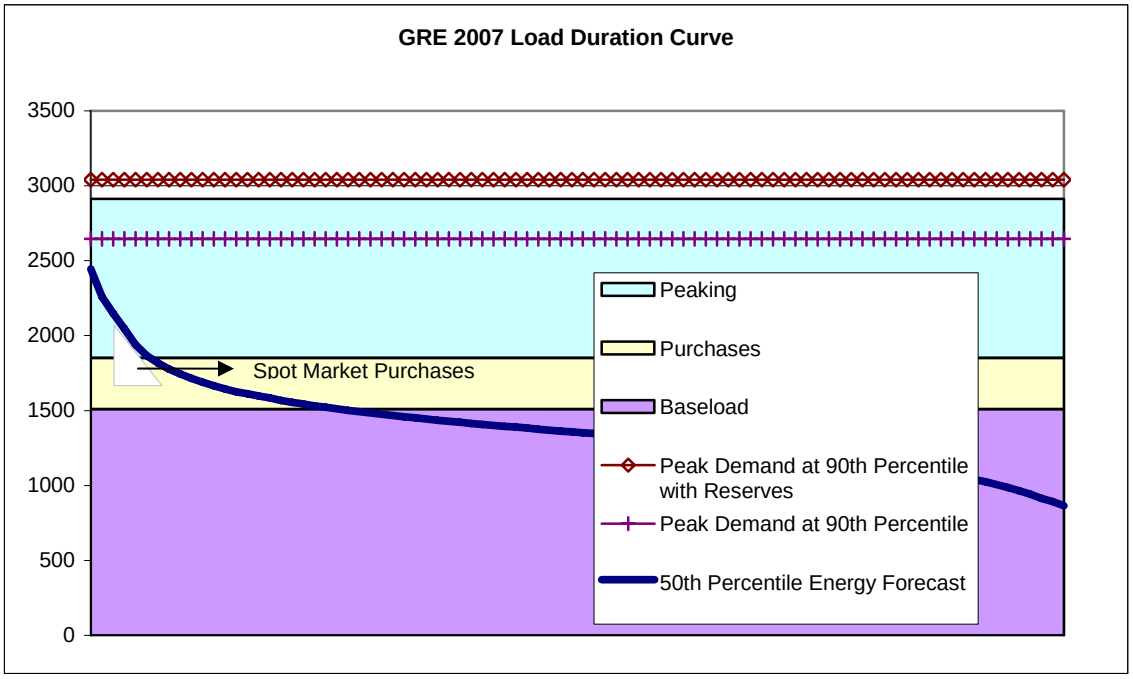
Over the 15 year forecast period shown from 2005 – 2020, GRE's energy needs are projected to grow at an average annual rate of 2.4 %.This rate of

growth is slower than the projected growth of GRE's demand, shown in Figure 2-1.

2.2.2 Load Duration Curve

A load duration curve can be used to illustrate how resources are used in serving load. The capacity of the resources available to serve load is stacked under a curve created by sorting the hourly loads from largest to smallest. (Actual dispatch of the units is complicated by operational considerations including minimum loading on units, market energy transactions, scheduled/unscheduled maintenance, operating reserves, transmission system support needs and daily load swings.) The area under the curve reflects the energy for the time period covered by the curve. Based on the extent a particular resource is "covered" by the load duration curve, the chart indicates the amount of energy supplied by the different types of resources. The portion of the load duration curve "breaking through" the stack of resources is the portion requiring new resources. The shape of the load duration curve above the stack of resources provides a picture of the type of resource that could best serve that load.

Figure 2-4 - GRE's Load Duration Curve



A load duration curve greatly simplifies the complexities associated with resource planning. However, it provides a useful visual illustration of the nature of GRE's current needs. As can be seen on the graph, the capacity needs are for a very few hours and are largely necessary to cover GRE's reserve requirements at its highest peak loads. Further, this graph suggests that all of GRE's peaking units would run at appropriate capacity factors, approximately 10 percent or less[2]. However, GRE expects that all of its peaking plants will operate at even lower capacity factors than this figure would suggest. As already explained, GRE supplements its resources with economic energy purchases from the market. The wedge overlaying the graph (within the peaking segment) illustrates how GRE envisions those purchases supplementing its resources.

2.3 Peaking Resources Best Match Need

GRE's forecasted demand is growing faster than its energy needs. GRE expects to see its load factor to continue declining slightly. Thus, GRE's capacity deficit is projected to occur over very few hours. Since the capacity need is much greater than the energy need, a peaking plant is best to meet these needs.

This conclusion is consistent with GRE's past analysis. GRE's 2003 IRP presented modeling results that showed building either an intermediate type combined-cycle combustion turbine or a peaking type simple-cycle combustion turbine as being optimal based on very similar Present Value Revenue Requirements (PVRR) for the two plant alternatives. In its subsequent IRP update, GRE announced it had entered into a new power-purchase contract that largely met its intermediate needs. This intermediate purchase shifted GRE's immediate needs more clearly toward peaking, and the analysis completed herein for the proposed project confirms that peaking is the true need.

Recent market conditions have further emphasized the need for peaking power. As previously explained, GRE often makes short-term purchases when market energy prices make it advantageous. In many instances, GRE has seen market energy delivered for several hours, only to have its energy schedules cut at the highest peak times due to transmission constraints on the grid. GRE then covers its load by running its existing peaking plants. While the new

[2] Generally, peaking plants are projected to run at capacity factors less than 10 percent. However, some of GRE's existing peaking facilities at Lakefield Junction have demonstrated the ability to run at capacity factors in the 20 percent range during some months.

MISO market may assist in delivering this type of energy, the transmission constraints will be reflected in the price rather than through cut schedules. Thus, GRE is not confident that access to economic energy at the highest peak times will improve significantly.

2.4 Additional Considerations

The project is the best alternative to provide GRE the peaking resource for its member-owners. Peaking facilities have a lower environmental impact than other types of generation due to the lower capacity factor. This project utilizes natural gas as its only fuel source resulting in some of the lowest possible emissions for a power generating facility of this size. In addition to the fuel choice, GRE's choice of combustion turbine technology – dry low NOx – results in low emissions levels. Siting of the project also has been done with considerations to minimize environmental impacts. It is being built on an existing peaking plant site minimizing the amount of additional land that will be converted from its existing use, whether agricultural or natural. It is also sited to minimize the amount of gas pipeline and transmission line construction, which limits the associated environmental impacts. In addition, the transmission improvements associated with the project will help improve transmission system reliability. The project would be served using 69kV transmission, and therefore the project does not require a certificate of need for a high voltage transmission line.

GRE has not conducted any promotional activities that have measurably contributed to the need for the Project. GRE has implemented DSM programs that are designed to shift electrical usage to off-peak hours and reduce the summer peak demand. Residential air conditioner usage is a primary driver of GRE's summer peaks. GRE has increased its focus on residential air conditioner programs that reduce demand at peak, as described further in Section 4.3.

The project will provide socially beneficial uses by supplying the member-owners with reliable, low-cost power. Maintaining the economic health of a region is a social benefit and is dependent on having reliable, low-cost electricity. The Cambridge area will also benefit by the revenues generated during construction and from the two to three additional skilled workers needed to operate the project.

2.5 Summary of GRE's Current Energy and Capacity Needs

Clearly GRE is experiencing significant growth in the time horizon presented in this filing and will need to make significant investments in new generating resources. This need is despite GRE's best efforts to maximize potential solutions within its system, such as pursuing DSM solutions, upgrades to existing generating facilities (both of which are addressed further in Section 4) and prudent use of the energy markets. While GRE has a need for additional energy, its immediate needs are dominated by capacity rather than energy, which are best met by peaking power.

3 PROJECT DESCRIPTION

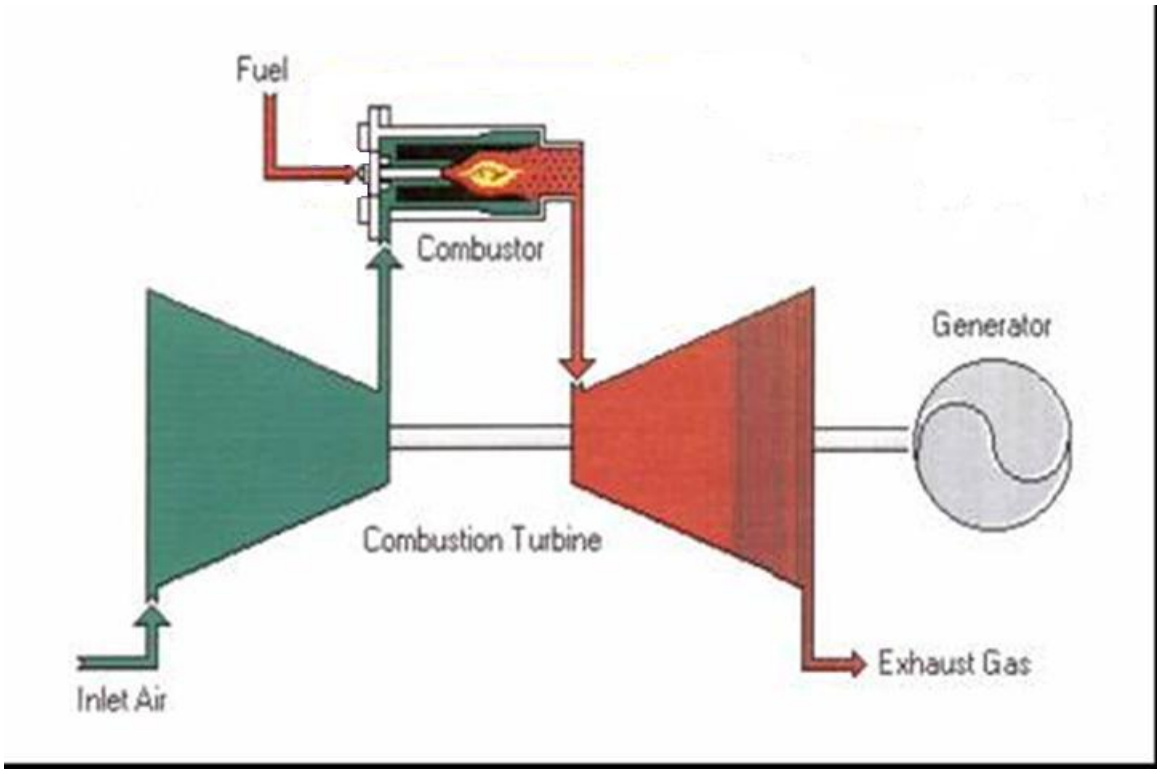
GRE is proposing to add one simple-cycle combustion turbine (SCCT) generator at the site of its existing Cambridge Peaking Plant near Cambridge, Minnesota. The project is expected to have a summer capability of approximately 170 MW and is expected to be operated primarily during periods when GRE's member demand is the highest.

This project is the addition of a single unit rather than multiple units on a single site like GRE's two most recent peaking resource additions, Lakefield Junction and Pleasant Valley Stations. Those resources were added to GRE's resource portfolio following a period when GRE was able to meet its peaking needs by making significant short term capacity purchases. At that time, as the regional capacity market tightened, GRE had an immediate need to add a large block of peaking resources, so it was a sound business decision to take advantage of siting multiple units on one site. In today's environment of uncertain market conditions, it makes more sense to consider the timing of individual units in order to meet growing demand as it occurs, rather than all at once, as long as economies of scale are not lost.

The unit proposed for this project is a relatively large unit with good efficiency characteristics, as will be shown in this section. It is also large enough to take advantage of scale economies within a single unit. Smaller units would have higher unit costs than the proposed unit. On the other hand, multiple large units (similar to the size of the proposal) would require finding a new site, rather than making use of the existing site and would also likely require a much greater transmission investment than that required for the proposed project or for the recent peaking additions of Lakefield Junction and Pleasant Valley Stations. Therefore, the size of the project maximizes the value of technology efficiencies, land use, and the transmission system.

Figure 3-1 depicts the typical SCCT schematic.

Figure 3-1 - Typical SCCT Schematic



3.1 Project Location

The project will be built at GRE's existing Cambridge Peaking Plant site, which is located at 2438 349th Avenue NE, Cambridge, Minnesota. The site is approximately forty miles north of Minneapolis and the specific location of the project will be in the northeast quarter of Section 21, Township 36N, Range 23W in Isanti County. Figure 3-2 depicts the site location.

The site consists of two parcels, one of approximately 11 acres located on the south side of 349th Avenue. The second parcel is approximately two acres directly across 349th Avenue. The site is 1/4 miles east of Minnesota Highway 65. The land immediately surrounding the site is used for agriculture. Figure 3-3 shows the layout of the two parcels with the proposed SCCT.

Figure 3-2 - Site Location

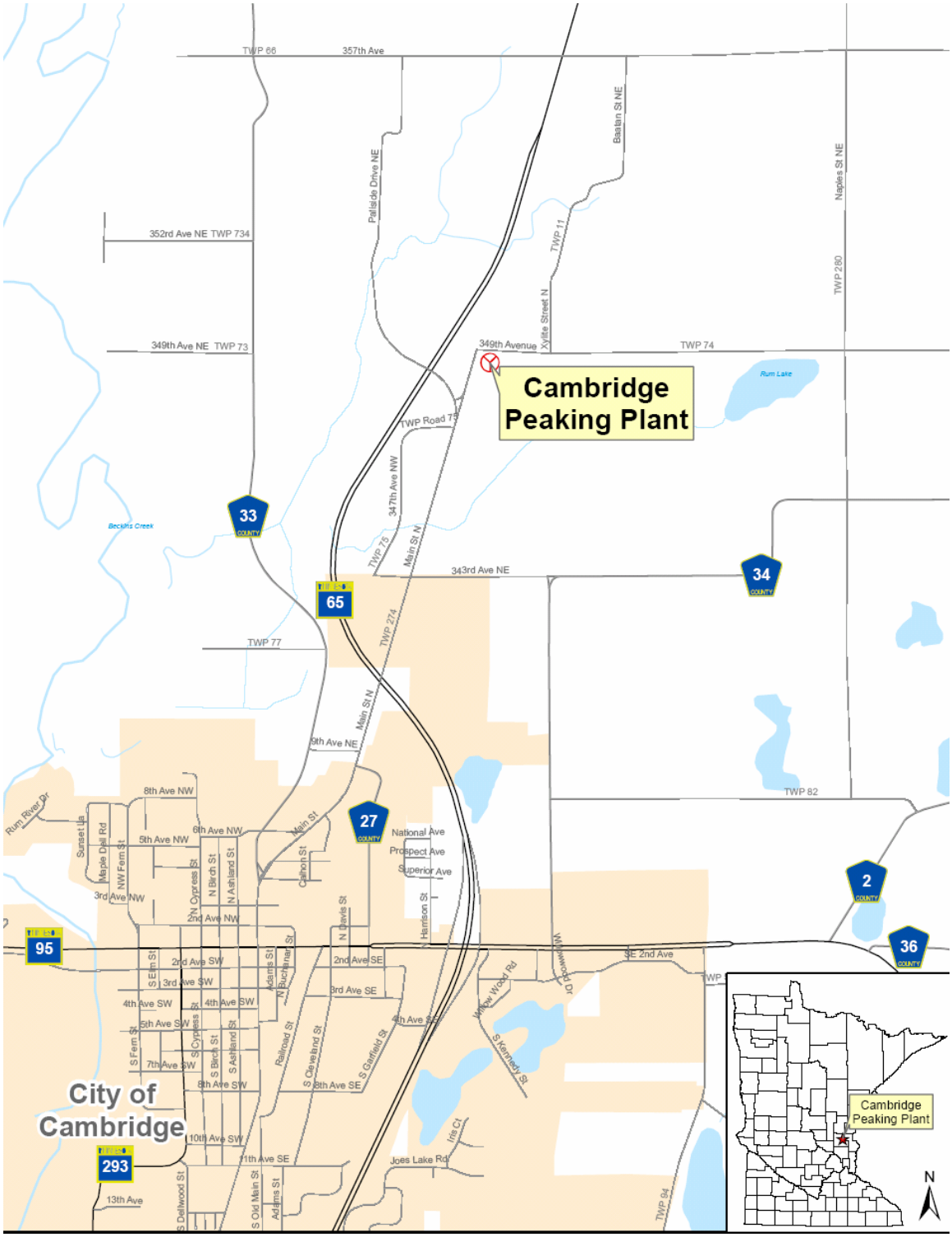
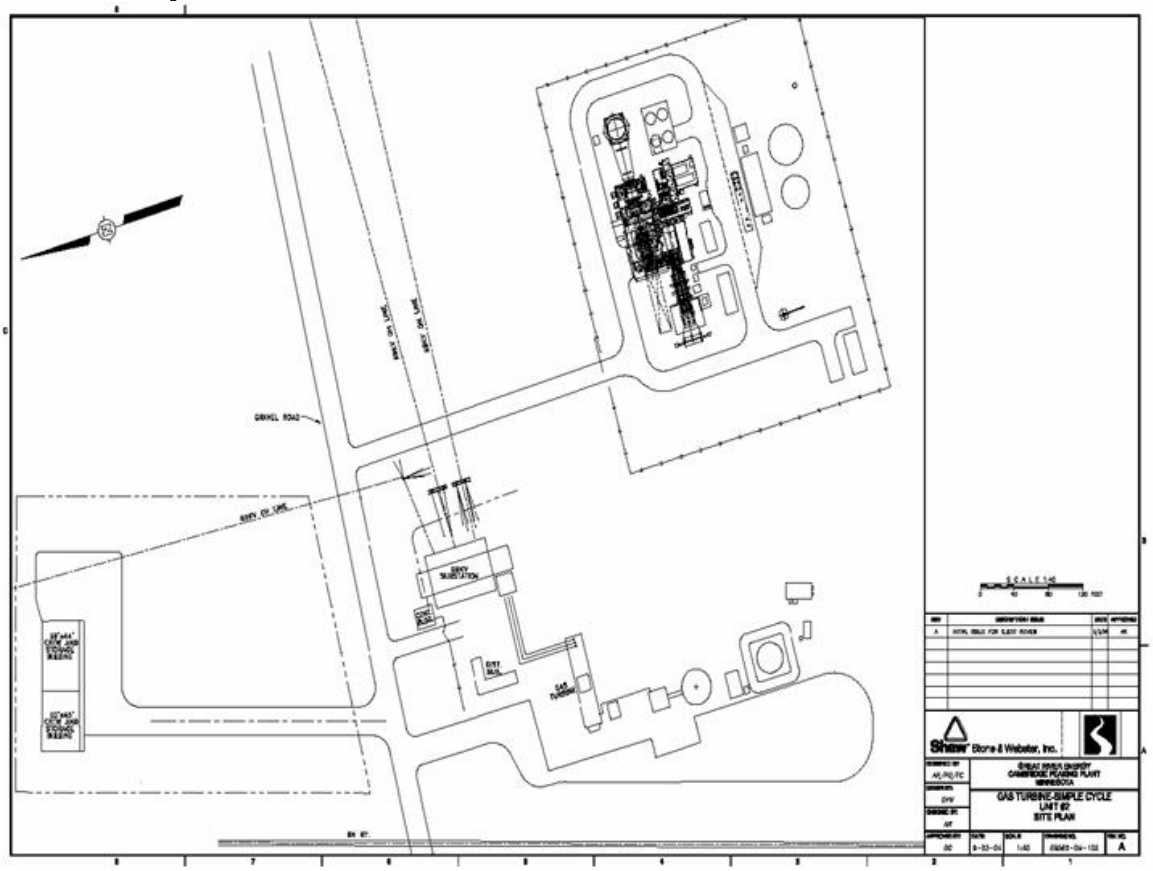


Figure 3-3 - Site Layout



3.2 Combustion Turbine/Generator

The combustion turbine (CT) for the project will be "F" class technology, which will result in the facility being one of the most efficient simple-cycle generation sources in the region. The project will have a peak output of approximately 170 MW during Mid-Continent Area Power Pool (MAPP) summertime conditions. The project will utilize dry low NOx combustion technology to minimize emissions. The project is proposed to utilize a single fuel – natural gas – for electricity production.

3.3 Generator Step-Up Transformers

One generator step-up transformer (GSU) will be used to increase the voltage, supplied by the project at a lower voltage (13.8 -16 kV), up to the substation voltage of 69 kV. Details of the interconnection will be finalized once the interconnection studies have been completed and a final interconnection recommendation is provided by the Midwest Independent System Operator (MISO).

3.4 Water Storage

Two water storage tanks will be provided on site. One 300,000-gallon tank will be used to store raw water, and one 200,000-gallon tank will store demineralized water. Demineralized water will be used for operation of the evaporative cooler during the summer months and potentially wet compression power augmentation. Raw water will be used as make-up for the demineralizers, for fire suppression, and other ancillary plant uses.

3.5 Substation

The existing substation adjacent to the project site will be modified to interconnect and integrate the plant with the transmission grid. The final design of the substation modifications will be determined by system impact studies currently underway at the MISO. Interconnection voltage will be at 69 kV.

3.6 Natural Gas – Primary Fuel

3.6.1 Overview

The project will utilize a single fuel – natural gas - delivered via Northern Natural Gas Company's (NNG) interstate pipeline. A 0.5 mile, 10-inch lateral

natural gas pipeline will be constructed off of Northern Natural Gas Pipeline's 16-inch trunk-line. A town border station will be constructed on GRE's site.

GRE anticipates purchasing Interruptible Transport (IT) Service from NNG. If significant winter operation is anticipated, GRE may pursue purchasing firm transport capability on the secondary market. In addition, GRE will take advantage of some of NNG's tarriffed balancing and storage services to optimize operation of the project and ensure an adequate supply of natural gas for variable operations. GRE has experience in purchasing/scheduling natural gas at the mid-continent cash hubs. GRE will leverage its experience in the natural gas market with its conservative approach to price risk management in order to optimize operations and ensure an adequate fuel supply while providing rate certainty for its member cooperatives.

3.6.2 Fuel Supply Outlook

The fuel for the project will be supplied from two regions of North America – the southern mid-continent of the Lower-48 and the Western Canada Sedimentary Basin (WCSB). The mid-continent natural gas is extracted from natural gas wells in the Gulf of Mexico, Texas and Oklahoma and is injected directly into the Northern Natural Gas Interstate Pipeline System (NNG) at the wellheads. In addition, natural gas from wells in the Rocky Mountains of the Lower-48 is delivered to the mid-continent via the Trailblazer Interstate Pipeline, which interconnects with NNG near Beatrice, Nebraska. The WCSB gas is injected into the TransCanada Pipeline System at the wellhead and is delivered to the mid-continent through an interconnection with the Northern Border Interstate Pipeline (NBPL) at Port of Morgan, Montana. The NBPL also picks up natural gas from the Williston Basin of North Dakota and from the Dakota Gasification facility. The NBPL interconnects with NNG at Ventura, Iowa. TransCanada also interconnects with Great Lakes Gas Interstate Pipeline and Viking Gas Interstate Pipeline at Emerson, Manitoba. Great Lakes Gas interconnects with NNG at Carlton, Minnesota, and Viking Gas interconnects with NNG near North Branch, Minnesota.

It is estimated that current conventional supplies of natural gas will continue to decline over time. However, that decline is projected to be bolstered by non-conventional resources.

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

Production of natural gas from the Lower-48 is also expected to be bolstered through the emergence of 3D seismic technology for exploration. Marginal natural gas wells that have been left unexplored by the large producers may get a second look by the smaller independent exploration and production companies. This second look will be made possible because 3D seismic technology will allow the explorers to have a much higher degree of certainty in pinpointing the location of wells that have historically been difficult to locate. These marginal wells are expected to be the "low hanging fruit" in terms of building domestic production due to their close proximity to gathering and transportation infrastructure.

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

Great River Energy recognizes that even though the long-term supply of natural gas to the project looks stable over the life of the project, natural gas price spikes could occur due to business cycles. GRE also recognizes that the price of natural gas will not likely drop below $3.50/MMBtu in real dollar terms over the life of the project. In fact, the development of natural gas supplies from CBM, Alaska and LNG will require a real natural gas price between $3.50/MMBtu and $4.00/MMBtu. However, GRE's exposure to the natural gas market will be limited due to the peaking nature of the project and the seasonality of the project's natural gas use. The additional 674,259 Mcf of annual natural gas exposure generated through expected operations of the project is manageable from a price risk management point-of-view. In addition, the majority of the annual natural gas consumption is expected to occur during the summer months when natural gas prices have historically displayed lower variability and volatility.

3.7 Plant Details & Operation

3.7.1 Overview

The project will operate as a peaking facility to provide electric energy during times of GRE's peak demand. GRE currently fulfills its peaking needs primarily through the operation of its Pleasant Valley Station and Lakefield Junction Station. Pleasant Valley and Lakefield Junction are dual-fuel peaking plants that became commercially operational in May of 2001. It is anticipated that the project will have an annual capacity factor of approximately five to ten percent. The plant is expected to have a short start-up sequence for an "F Class" machine at 8 minutes, and the ramp rate is expected to be 12 MW/minute. Table 3-1 provides pro forma details of the project's operational characteristics.

3.7.2 Plant Efficiency

The project will be designed to be one of the most efficient SCCTs in the region with a full load heat rate (higher heating value) of 9,730 Btu/kWh at site-specific conditions during winter months. The heat rate equates to an efficiency of 37%. Heat rejected through the exhaust stacks is expected to be 1,013 MMBtu/hr at full load during the summer months.

Table 3-1 - Project Operational Characteristics

Characteristic	Data	MN Rule
Facility Description		
Unit Type	F-Class	
Prime Mover	Combustion Turbine	
Number of Units	1	
Summer Capability (site specific)[1]	170 MW	7849.0250, A(1)
Winter Capability (site specific)	190 MW	7849.0250, A(1)
Operating Cycle	Simple-cycle	7849.0250, A(2)
Expected Annual Capacity Factor	9.6%	7849.0250, A(2)
Expected Heat Rate/Efficiency (Summer site specific)[2]	10,200 Btu/kWh (HHV)/35%	7849.0250, A(4)
Expected Heat Rate/Efficiency (Winter site specific)[2]	9,730 Btu/kWh (HHV)/37%	7849.0250, A(4)
Heat Rejected through exhaust (Summer)	1013 MMBtu/hr	
Heat Rejected through exhaust (Winter)	1188 MMBtu/hr	
Fuel Description		
Fuel Source: Natural Gas only	Northern Natural Gas Pipeline	7849.0320, C(1)
Fuel Requirement: Natural Gas only (Summer)[2]	1,546 MCf/hr	7849.0320, C(2)
Fuel Requirement: Natural Gas only (Winter)[2]	1,771 MCf/hr	7849.0320, C(2)
Expected Annual Fuel Requirement	1,305,360 MCf	7849.0320, C(2)
Heat Input (Summer - HHV)[2]	1554 MMBtu/hr	7849.0320, C(3)
Heat Input (Winter - HHV)[2]	1780 MMBtu/hr	7849.0320, C(3)
Fuel Heat Content: Natural Gas	1.005 MMBtu/MCf	7849.0320, C(4)
Fuel Sulfur Content: Natural Gas	5.5 mg/m^3	7849.0320, C(5)
Fuel Ash Content: Natural Gas	None	7849.0320, C(5)
Fuel Moisture Content: Natural Gas	<80 mg/m^3	7849.0320, C(5)
Water Use		
Estimated maximum groundwater pumping rate[3]	108 gpm	7849.0320, E(1)
Estimated maximum surface water appropriation[3]	0 ft^3/sec	7849.0320, E(1)
Estimated annual groundwater appropriation[4]	3. million gal/yr	7849.0320, E(2)
Annual consumption[4]	9.2 acre-feet	7849.0320, E(3)
Emissions[5]		
Maximum Sulfur Dioxide Emissions[2]	5.7 lb/hr	7849.0320, D(1)
Maximum Nitrogen Oxides Emissions[2]	169 lb/hr	7849.0320, D(1)
Maximum Particulates Emissions[2]	15 lb/hr	7849.0320, D(1)
1,3-Butadiene	0.00072 lb/hr	7849.0320, D(1)
Acetaldehyde	0.067 lb/hr	7849.0320, D(1)
Acrolein	0.011 lb/hr	7849.0320, D(1)
Benzene	0.020 lb/hr	7849.0320, D(1)
Ethyl benzene	0.053 lb/hr	7849.0320, D(1)
Formaldehyde	1.2 lb/hr	7849.0320, D(1)
Naphthalene	0.0022 lb/hr	7849.0320, D(1)
PAH	0.0037 lb/hr	7849.0320, D(1)
Propylene oxide	0.048 lb/hr	7849.0320, D(1)
Toluene	0.22 lb/hr	7849.0320, D(1)
Xylenes	0.11 lb/hr	7849.0320, D(1)

1 With evaporative cooler in service.
2 Under base load operations.
3 When unit is on-line.
4 Assuming a 9.6% annual capacity factor and utilization of evapoartive cooler for 5.7% of annual operation.
5 More emissions information can be found in Table 3-2.

3.8 Employment Opportunities

The labor requirements for the construction, operation, and maintenance phases of the project will benefit the local communities by providing revenue to local businesses. During construction, approximately 100 skilled craft workers will work at the site, most of them for about one year. Day-to-day operation of the plant will be conducted by two to three full-time employees. During scheduled annual maintenance on the plant, seven to ten additional skilled craft workers will work at the site over a two to three week period depending on the level of maintenance activities.

3.9 Maintenance

GRE has extensive experience operating and maintaining (O&M) CTs including General Electric (GE) Frame 5, Pratt & Whitney FT4, GE 7EA, Siemens V84.3A2, and Westinghouse 501D5A. GRE maintains those units using a combination of GRE staff and unit vendor staff through long-term service agreements. GRE is committed to providing its operations and maintenance staff with the very best in continuing education and training to ensure a high level of reliability and availability of its generation assets. GRE will continue to utilize its O&M model for the project by utilizing the human intelligence it has gained from O&M on its existing facilities to train and cross-train the project operators. An existing warehouse will be utilized to house the critical parts and tools needed for maintenance and reliable operations. GRE will maintain the project according to prudent utility practice with the intent to provide excellent reliability and availability.

3.10 Site Selection

GRE considered numerous sites before identifying the preferred site. Several factors were considered when evaluating sites including access to an existing electric transmission system, access to existing high pressure natural gas pipelines, cost of developing new infrastructure versus developing a site with legacy infrastructure, land use constraints, water availability and disposal, local government support, ambient air quality classification, and other environmental constraints.

The site selected met all the siting factors considered with the lowest overall costs and environmental impacts.

3.11 Security & Plant Access

Access to the project and substation will be restricted through the use of perimeter fences and monitored access gates. On-site security cameras will be installed to assist in monitoring the site.

3.11.1 Road Access

The site is near Minnesota Highway 65. Access to the site from the highway will be via County Road 30. The primary plant entrance will be located off of 349th Ave. NE on the north side of the site.

3.11.2 Rail Access

A rail line exists adjacent to the selected site. The nearest siding is located in Cambridge - approximately two miles southwest of the selected site. This siding will be used for the delivery of major equipment during construction.

3.11.3 Security Measures

The project site will be surrounded by an 8-foot chain-link fence. Access into the project will be controlled by an automatic gate with the option for manual operations from the project's Control Room. The project site will be monitored through closed circuit television linked to the project's Control Room and GRE's 24-hour System Operations Center in Elk River, Minnesota. GRE will work with the local law enforcement agencies to ensure a high level of security.

3.12 Transmission Interconnection and Service

The existing 69-kV substation will be modified to accommodate the electrical output from the project generator. The substation bus feeds four 69-kV lines as well as the local distribution substation located at the site. Preliminary results from the MISO transmission studies indicate that sections of lines will need to be upgraded either through reconductoring or rebuilding at the 69-kV voltage. This is discussed further in Appendix D.

3.13 Fire Protection and Safety

The project design will include a 300,000-gallon raw water storage tank, with approximately 200,000 gallons of that reserved for fire protection needs. The

design of the project will include a pressurized hydrant loop around the facility. The design of all buildings and enclosures will meet State Fire Marshal, as well as insurance, and local fire codes.

A CO2 fire suppression system will be installed inside the turbine enclosure, and fire detection equipment and alarms will be included in the control and switchgear buildings.

Safety procedures, as mandated by OSHA, will be followed during the construction and operations of the facility.

3.14 Air Emissions

3.14.1 Emissions from Operation

The project will be fueled by natural gas, one of the cleanest fuels for producing electricity, which will result in substantially lower emissions than would occur with other fuels such as oil. Table 3-2 summarizes the expected emission from a new F-Class combustion turbine on a typical summer day. Emissions of nitrogen oxides (NOx) will be minimized by the use of dry low NOx combustion technology. GRE's Pleasant Valley Station operates Siemens-Westinghouse V84 CTs, which are F-Class machines. The rates shown in Table 3-2 are manufacturer's data for a V84. While GRE expects the unit to operate below these rates, the manufacturer's information is not guaranteed at this time and would not apply if equipment from a different manufacturer were to be procured. Nevertheless, the data is representatively conservative.

An air emission source permit will need to be obtained from the Minnesota Pollution Control Agency (MPCA) prior to starting construction of the project and to authorize operation of the project. Because GRE plans to operate the project as a peaking unit, GRE intends to cap annual air emissions from the project such that it could not be continuously operated at its rated capacity.

Impacts to the ambient air quality are expected to be negligible. This assumption is based on the low emission rates, the expected operating capacity of the project, the exhaust gas characteristics, and GRE's experience operating similar facilities. Consequently, the estimated range of maximum

contributions to 24-hour average ground level concentrations requested by Minn. Rules pt. 7849.0320 (D) (2) are also negligible, and will be less than permitting requirements. Estimates of actual impacts will be generated through computer-based dispersion modeling of the worst-case emissions scenario for the project as part of the MEQB site permitting process. At this time, modeling has not been completed.

There will be no radioactive emissions associated with the operation of the project. Furthermore, the project will not entail the installation of any instrumentation or monitoring device that requires a radioactive source for its operation.

Table 3-2 - Air Emission Estimates[1]

Emission Type	Estimated Emission Rate (lb/hr)	Emissions at 840[2] hours of operation (tons)
Nitrogen Oxides	169	71
Carbon Monoxide	37	16
Volatile Organic Compounds	9.4	3.9
Particulate Matter	15	6.1
Sulfur Dioxide	37	2.4
Formaldehyde	1.2	0.5
Toluene	0.22	0.05
Xylene	0.0.11	0.1
Acetaldehyde	0.07	0.03
Ethyl Benzene	0.05	0.02
Propylene Oxide	0.05	0.02
Benzene	0.02	0.008
Acrolein	0.01	0.004
Poly Aromatic Hydrocarbons	0.004	0.002
Naphthalene	0.002	0.0009
1,3-Butadiene	0.0007	0.0003

1. Manufacturer's information for a Siemens-Westinghouse V84 fueled with natural gas at baseload conditions, 90ºF, 60% relative humidity, and evaporative coolers on. Actual emissions would be higher on a cold, winter day; however, the project is being installed primarily as a summer peaker and therefore summer operating data is shown.

2. 840 hours of baseload operation is roughly equivalent to a 9.6% capacity factor.

3.14.2 Fugitive Dust

Operation of the project will not result in additional fugitive dust emissions from the site. Fugitive dust emissions could be generated during the site preparation and construction activities, and any such emissions will be minimized by the application of water or other dust suppressants.

3.15 Wastewater Handling and Disposal

3.15.1 Operations Wastewater

The project will not require large volumes of water for operation. The only source of operations wastewater will be the evaporative cooler. When the evaporative cooler is in operation, approximately 15-75 gpm of blow down wastewater will be generated. The actual blow down rate will be determined based on water quality data for the site, which has not yet been obtained.

Some of the wastewater (compressor wash water) will be generated periodically during maintenance on the CT. This process wastewater will be stored in an on-site tank. The process wastewater will be off-loaded into tanker trucks and hauled to a municipal wastewater treatment plant for ultimate treatment and disposal.

Some of the wastewater from the site (except for the compressor wash water and sanitary wastewater) will be processed through an oil/water separator and then pumped to an on-site retention pond. GRE plans to seek a wastewater permit from the MPCA that will allow it to discharge the retention pond to an adjacent ditch that would likely flow into Beckins Creek, which discharges to the Rum River.

3.16 Storm Water Handling and Disposal

The project will include numerous catch basins for oil-containing equipment. The catch-basins are often exposed to ambient weather conditions and capture storm water run-off. The drains from the catch basins will discharge to the oil/water separator. The water from the oil/water separator will be pumped to the on-site retention pond where it will mix with the evaporative cooler blow down water. GRE plans to obtain a National Pollutant Discharge Elimination System wastewater discharge permit from the MPCA that will allow discharging the retention pond to an adjacent ditch.

3.16.1 Handling during Construction

A construction storm water permit will be obtained prior to any site grading. Storm water will be managed in accordance with the permit.

3.17 Oil Waste Handling and Disposal

The only waste oil generated by the project will be from periodic changes of lubricating oils. These oils will be collected and handled for disposal in accordance with state regulations.

3.18 Solid Waste Handling and Disposal

There will be minimal amount of solid wasted generated by the operation of the project. Typical wastes will include used shop rags, which will be handled and disposed of off site in accordance with state regulations.

Solid waste generated during the construction of the project will include packaging and freight materials, paints, solvents, and adhesives. All wastes will be managed in accordance with state regulations and disposed of off site.

3.19 Primary Water Use

Water will be provided by on-site wells for use primarily in evaporative cooler and potentially for wet compression. Raw water will be pumped from the wells into the service water tank, which will supply raw water to the demineralizer skid. The instantaneous maximum use rate for the raw water source is expected to be 108 gallons per minute (gpm).

Well water will also be used to supply other plant water needs such as fire suppression and other ancillary plant water uses. The instantaneous maximum use rate for these services is expected to be 50 gpm.

Drinking water will be provided by bottled water.

3.20 Noise Impacts

Noise from operation of the new CT will comply with the state noise standards. The new combustion turbine is expected to be quieter than the existing oil-fired combustion turbine at Cambridge Station. If both turbines are operating simultaneously, the noise level at the nearest residence is estimated to increase by less than three decibels (A scale-weighted (dBA). According to the Minnesota Pollution Control Agency's document, "A Guide

to Noise Control in Minnesota"[3], plus or minus three decibels is the "threshold of perception" for the human ear while plus or minus five decibels is "clearly noticeable.". Thus, noise from the new CT is not expected to be noticeable at the nearest residences. Currently, noise sources in the area surrounding the site are primarily associated with traffic flow on Highway 65 and local county roads, rail traffic on the Burlington Northern Santa Fe (BNSF) rail line adjacent to the site and operation of GRE's existing peaking plant.

Construction noise will be mitigated by requiring the construction contractor to use properly muffled equipment, by routing truck traffic to the greatest extent possible away from area residents and by restricting nighttime activities.

3.21 Traffic

3.21.1 Construction Traffic

Traffic on County Road 30 and on 349th Avenue NE will increase during construction. The amount of traffic is not expected to exceed the level that can be safely accommodated. Discussions will be held with township and county officials and local residents to minimize the local impact of the construction traffic. Approximately 100 construction workers are expected to be on site during peak construction activities.

3.21.2 Operations Traffic

During operation, the additional traffic due to the project will be minimal. The project is expected to have a full time staff of approximately 2 people, spread over one to two shifts of operation.

3.22 Economic Considerations

The project costs are summarized in Table 3-3. The information contained therein is based on GRE's on-going operating experience at Pleasant Valley Station (PVS), manufacturers' estimates and publicly available information. A comparison of the project with potential alternatives is provided in Section 4.

[3] [http://www.pca.state.mn.us/programs/pubs/noise.pdf]

Table 3-3 - Project Cost Analysis

Item	Units	Project Data	Assumptions	MN Rule
Project Description				
Base Capability (Summer, site-specific rating)	MW	170	Manufacturer *pro forma* estimate	7849.025, A(1)
Cost Basis	Cal Yr	2004		
Life of Project	Years	30	Typical accounting life	7849.025, C(2)
Operating Cycle		Simple		7849.025, A(2)
Annual Capacity Factor	%	9.6%	PVS experience	7849.025, A(2)
Annual Operating Time	Hours	840	Formula	
Average Annual Availability	%	97.5	PVS ops experience	7849.025, C(3)
Fuel Type		Nat Gas		7849.025, A(3)
Heat Input (HHV)	MMBtu/hr	1,554	PVS ops experience	
Heat Rate (HHV) - Summer Rating	Btu/kWh	10,200	PVS ops experience	7849.025, A(4)
Efficiency (HHV) - Summer Rating	%	35	Formula	7849.025, C(8)
Project Capital Cost	$/kW	406	Overnight cost w/o IDC	
Fixed O&M Costs	$/kW-yr	3.46	PVS experience	
Fuel Costs	$/MMBtu	5.73	EIA *2005 AEO* plus transport & balancing	7849.025, C(4)
Non-Fuel Variable O&M Costs	$/MWh	8.41	Includes fired-hour costs & start charge	7849.025, C(5)
Capacity Costs (Fixed)				**7849.025, C(1)**
Total Project Capital Cost	$	69,020,000	Formula	
Annual Fixed O&M	$	588,200	Formula	
Total Annual Fixed Costs	$	6,523,920	8.6% annual FCs + Fixed O&M	
Project Capacity Cost	$/kW-yr	38.38	Formula	
Project Capacity Cost	$/kWh	0.046	Formula	
Production Costs (Variable)				
Net Annual Generation	MWh	142,800	Formula	
Annual Fuel Consumption	MMBtu	1,305,360	Formula	
Annual Fuel Cost	$	7,483,015	Formula	
Annual Non-Fuel Variable O&M Cost	$	1,200,948	Formula	
Total Project Variable Generation Cost	$	8,683,963	Formula	
Project Fuel Cost	$/kWh	0.052	Formula	7849.025, C(4)
Project Total Energy Cost	$/kWh	0.061	Formula	
Total Cost	**$/kWh**	**0.106**	**Formula**	**7849.025, C(6)**

3.23 Use of Space

The project will be located on land that is currently used for utility operations. Adjacent property is used for agricultural and transportation purposes.

The project boundaries will utilize the parcel south of 349th Avenue NE for the CT, substation, water tanks and other balance of plant equipment. The parcel north of 349th Avenue NE will be utilized for shop space and parts storage.

3.24 Required Permits and Approvals

Table 3-4 lists permits and approvals that may be required to construct and operate the project.

Table 3-4 - Potential Approvals Required for Construction and Operation

Approval Type	Authority	Comments
Certificate of Need	Minnesota Public Utilities Commission	Required for construction of the power plant.
Environmental review and assessment: 1. RUS Finding of No Significant Impacts (FONSI) for the plant site and transmission line. 2. MEQB Site Permit for the plant site.	Rural Utilities Service - Environmental Assessment with Scoping Minnesota Environmental Quality Board - Site Permit	Requirements of these two reviews are fairly similar. There are some procedural differences, but GRE will attempt to complete the reviews jointly and concurrently. Minn. Rules exempt the transmission lines from review, but RUS rules will require certain lines to be included.
Permanent Exemption for New Facilities	Department of Energy	Allows the use of natural gas for power production.
Sales Tap Approval	Federal Energy Regulatory Commission	Approval to tap into the existing interstate gas pipeline. This will be obtained by the pipeline company.
Part 70 Air Emissions Source Construction and Operating Permit	Minnesota Pollution Control Agency	This permit cannot be issued until after issuance of the MEQB Site Permit. The permit must be issued before starting construction.
Storm Water Construction Permit	Minnesota Pollution Control Agency	A general permit is available for most construction projects.
National Pollutant Discharge Elimination System (NPDES) Permit	Minnesota Pollution Control Agency	This permit would authorize the discharge of the evaporative cooling water and site storm water runoff after plant construction.
Groundwater Appropriation Permit	Minnesota Department of Natural Resources	Notification of well drilling and appropriation of surface or groundwater water.
Spill Prevention Control and Countermeasure (SPCC) Plan	Minnesota Pollution Control Agency	GRE must update the existing SPCC Plan within six months of bringing additional oil storage capacity on site.
Electrical Inspection	Board of Electricity	Permit and inspection of building electrical systems.
Public Water Supply Plan Review	Minnesota Department of Health	Potable water supply.
Local Building & Construction Permits	Isanti County Cambridge Township	

4 ALTERNATIVES TO THE PROPOSED PROJECT

4.1 Alternatives Review

GRE considered the following characteristics when reviewing the possible alternatives to the proposed project:

- Suitability for operating at less than 20 percent capacity factor.
- Ability to procure and install the alternative in the time frame required to meet GRE's need (summer 2007).
- Reliability of the technology.
- Timeliness when called upon to operate.
- Energy efficiency (heat rate).
- Cost effectiveness.
- Environmental impacts.
- Ability to limit the risk to GRE from financial, social and technological risk that GRE and its member-owners cannot control.

4.1.1 Primary Objectives for Screening

Using the characteristics listed above to review every possible alternative would be a lengthy process. Therefore, GRE first screened potential alternatives to see if they met a few critical objectives, including:

- Ability to procure and install at least 170 MW of summer accredited capacity prior to the summer of 2007.
- Operating characteristics suitable to peaking operation (rapid availability, dispatchable, extremely reliable operation).
- Cost-effective when compared to the proposed project.

If an alternative met the first two of these three objectives, it was considered as a suitable alternative and analyzed further in Section 4.5.

4.1.2 Alternative Resources Considered

Prior to completing a more extensive analysis of alternatives, GRE examined whether renewable energy or energy conservation measures could meet the needs. After considering those alternatives, GRE analyzed the following resource types, discussed further in Section 4.4.

- Purchased power
- Upgrades to existing resources
- New transmission
- Other Fossil-Fuel Technologies, including:
    - Coal
    - Oil-fired combustion turbine
    - Combined cycle combustion turbine
- Customer-owned distributed generation
- Emerging technologies, including:
    - Micro turbines
    - Fuel cells
    - Energy storage (such as batteries, pumped storage hydro, compressed air energy storage, and super conducting magnetic energy storage)

4.2 Renewable Energy

As GRE continues to grow, its new generation resources will include more renewable energy sources. GRE's generation mix already includes wind energy, refuse-derived fuel and hydropower. The organization is looking at ways to further diversify its energy portfolio by exploring biomass, fuel cells and other technologies as available.

GRE considered several different types of renewable energy resources in its analysis including wind, biomass (including an ethanol-fueled peaking plant), hydro and solar. However, GRE's strong commitment to add renewable

resource development is unable to satisfy its current need for additional peaking power in the near term.

4.2.1 Wind

Wind energy is a renewable resource that has been well utilized because of its reasonable average energy cost and abundant supply in the region. GRE's wind energy is an integral part of its overall energy portfolio. Energy from the Chandler Hills Wind Farm serves the Wellspring Renewable Energy Program subscribers. In addition, GRE purchases from a wind project in Jackson County, Minnesota and from a wind project in Dodge Center, Minnesota, resulting in a total of about 18 MW of wind in GRE's current portfolio of resources.

GRE's commitment to wind energy is expanding with power from Minnesota's first commercial-scale, landowner-developed wind farm this fall. Trimont Area Wind Farm (TAWF), a coalition of landowners in Jackson and Martin counties, won the contract to serve GRE through a request for proposals (RFP) process initiated in 2003. Subsequent to its selection by GRE, TAWF chose PPM Energy to develop the project on its behalf. The 100-MW wind project is expected to be online in October 2005.

Improvements have been made to increase wind turbine reliability and decrease costs over the last several years. However, the average cost of wind generation is not the most relevant measure in this analysis to meet current capacity and energy needs. It is whether the resource can meet the primary objectives of GRE's immediate capacity and energy needs, namely, adequate capacity online and accredited prior to summer 2007, and operating characteristics suitable to peaking operation.

Wind generation is not an effective resource to meet peaking needs because of its intermittent nature and the low correlation of wind output to summer peak conditions. Having a dispatchable resource is a key objective of this project. Because wind generation does not have suitable operating characteristics to meet GRE's peaking needs, it will not be considered for further evaluation.

4.2.2 Biomass

Biomass encompasses a wide variety of renewable fuels. Renewable fuels may be utilized via burning in a steam cycle, gasified for use in a combustion turbine or burned directly in a combustion turbine or other internal combustion device. Solid biomass fuels include wood and waste wood, switchgrass and alfalfa stems. Ethanol derived from corn is also considered a renewable fuel.

GRE has significant experience with biomass resources, which aided in its analysis of whether biomass could serve its current needs. GRE operates Elk River Station that burns refuse-derived fuel (RDF) – material produced from processing municipal waste – to produce electricity. As a waste-to-energy power plant, Elk River Station diverts about 270,000 tons of municipal solid waste from community landfills annually.

GRE continues to pursue anaerobic digester technology in dairy applications. Anaerobic digesters show a lot of potential for mitigating the environmental impacts of dairy and swine feedlots while producing renewable energy. GRE implemented a special Biomass Grant Program to encourage the development of additional renewable energy technologies using biomass resources to show their commitment. The organization awarded its first $100,000 biomass grant in 2003.

GRE's role serving rural cooperatives makes it well suited to continue pursuing the development of these types of biomass. However, the analysis shows that this type of development will not be adequate to meeting the needs of the currently proposed project. Having 170 MW of solid fuel biomass capacity available by 2007 is not feasible due to limited fuel availability and siting issues.

Furthermore, solid fuel power plants have operating characteristics consistent with baseload resources. For example, solid fuel plants generally operate at a higher capacity factor to allow planning and scheduling of producing and delivering the fuel to the power plant. Also, having a dedicated source of solid fuel is incompatible with a resource such as a peaking resource, which operates on an intermittent basis.

At the capacity factors expected for the project, a large biomass plant would not be a cost effective peaking alternative. This analysis is consistent with Dr. Steve Rakow's conclusion in his direct testimony in Docket No. IP3/CN-98-1453, (Lakefield Junction, pages 8 and 9), in which he concluded that biomass would not offer a cost effective peaking alternative based on a DOE study of six different biomass technologies. Solid fuel-based biomass is excluded from further analysis based on unavailability for summer 2007 and unsuitable operating characteristics.

4.2.3 Ethanol-Fueled Peaking Plant

An ethanol-fueled peaking facility is a logical renewable alternative to meet GRE's peaking needs. If the same equipment proposed for this project could be used for an ethanol-fired facility, the criterion of availability of 170 MW for summer 2007 could be met. However, the turbine manufacturers have no experience with firing ethanol in this equipment, and significant fuel storage and handling issues would arise with using ethanol as a primary fuel. In order to be accredited on ethanol, a 170-MW power plant would need approximately 400,000 gallons of ethanol stored on site. Other technical and economic issues related to this alternative are discussed further below.

Technical Issues: Combustion turbine manufacturers have shown little interest in developing a combustion turbine to burn ethanol; however, they do acknowledge that it is technically possible to do so.

GRE staff interviewed three major combustion turbine manufacturers regarding the prospect of developing a combustion turbine that would burn ethanol. The manufacturers indicated that they do not foresee a sufficient market to justify the research and development effort necessary to commercially develop an ethanol-fired combustion turbine. Even if GRE were willing to underwrite the costs of the effort, two of the three manufacturers indicated that they would not be able to dedicate any use of their combustion turbine testing facilities for such a purpose for two to three years because of other research and development currently underway. Unit output levels, emissions and construction materials would all have to be investigated further.

In general, the effects of burning ethanol in a combustion turbine are expected to include:

- Higher NOx emissions requiring the use of water injection (similar to fuel oil).
- More corrosion resistant materials required for fuel handling and storage components.
- The need to inject lubricity-improving additives.
- Maintenance costs equal to or higher than with the use of No. 2 fuel oil, which are higher than with natural gas as fuel.
- Increased ventilation and hazard detection equipment.
- Slightly higher output may be possible, but the heat rate would probably also be higher (less efficient).
- A requirement that the combustion turbine start up on natural gas, then switch to ethanol, which would require an initial investment in natural gas infrastructure to deliver the start-up fuel.

Economic Issues: The most expensive consideration of burning ethanol in a combustion turbine is the cost of the ethanol itself. GRE determined that the price of ethanol is reasonably estimated to range between $1.00 and $1.35 per gallon. Table 10-1 depicts the per-gallon price of ethanol, the equivalent price per million British Thermal Units (MMBtu) of ethanol, the estimated fuel cost of electricity production per megawatt hour and the price that natural gas would have to be to result in the same fuel cost of electricity production. For instance, ethanol priced at $1.00 per gallon could produce electricity at a cost of $136.00 per MWh. The natural gas price would have to be as high as $12.95 per MMBtu to produce electricity at that same cost.

Table 4-1 - Comparison of Fuel-Related Electricity Production Costs from a SSCT burning Ethanol vs. Natural Gas

Ethanol Price ($/gallon)	Ethanol Price ($/MMBtu)	Fuel Cost of Electricity Production ($/MWh)	Equivalent Natural Gas Price ($/MMBtu)
0.50	5.91	68.00	6.48
1.00	11.81	136.00	12.95
1.20	14.18	163.00	15.52
1.40	16.54	190.00	18.10

For comparison purposes, an ethanol-fueled alternative is included for further analysis in Section 4.5, even though the technical feasibility of converting the combustion turbines to burn ethanol is very much in doubt.

4.2.4 Hydro

Hydro resources are typically baseload or intermediate in nature rather than peaking. Initial capital costs are also usually high compared with peaking resources.

Within Minnesota (and the region) the potential for new hydro facilities is limited. Dr. Rakow's Lakefield Junction direct testimony cited a DOE study that indicated no sites with the potential for 100 MW or more of new hydro generation within Minnesota. (Direct Testimony, pages 8 and 9) The study indicated three sites in South Dakota with greater than 100 MW of capacity could be developed, two of which are controlled by the Corps of Engineers, and all significantly less than the capacity contemplated by this project. Dr. Rakow concluded that while Manitoba has substantial potential hydro resources yet to be developed, significant additional transmission would need to be built in order to bring those resources into the U.S. The cost of the added transmission ($180 million) makes further development of Canadian hydropower uneconomic compared with this project. Conditions have not changed substantially since Dr. Rakow's testimony although discussions are taking place to remedy some of these obstacles.

Hydropower cannot be developed by 2007, and it cannot meet the project's objectives for peaking plant operating characteristics. Therefore, hydro is not a reasonable alternative and will not be evaluated further.

4.2.5 Solar

Solar power is another intermittent resource similar to wind, except that there is less experience with solar generation in this region. As with wind, solar receives a relatively low ratio of accredited capacity to nameplate rating under the MAPP capacity accreditation process, requiring greater amounts of solar capacity to meet the project's objectives. The necessary amount of solar generating capacity could not be online by summer 2007. It also does not have appropriate operating characteristics, in that it is an intermittent resource. Therefore, solar fails to meet the primary objectives and will not be considered for further evaluation.

4.3 Energy Conservation Improvements

Through the use of load management and conservation measures, GRE reduced its summer peak demand in 2004 by 300 MW. This was achieved primarily through load management programs such as residential cycled air conditioners, interruptible irrigation, peak shave water heaters, and customer-owned generation. GRE expects to see continued, significant growth in these programs. In 2005, the impact of demand-side management programs on summer peak reduction is expected to increase by another 16 MW. It is likely that the success of these programs has delayed the need for additional peaking power; however, it is infeasible that an additional increase in the participation of these programs could entirely replace the 170 MW need for the current project.

GRE has a strong commitment to conservation as well as load management. In the past, the focus has been more directed to load management, as those programs best complemented the profile of the GRE's resources. In more recent years, GRE has increased its emphasis on conservation. GRE exceeds the legislative mandate of spending on demand-side management (DSM) programs, and it invests significant efforts into evaluating the programs to ensure GRE's focus is on the programs where energy savings could have the greatest impact for GRE and its members. To enhance these evaluations, in 2003 GRE retained Global Energy Partners, an EPRI affiliated company, to conduct an assessment of the organization's DSM effort and to assist in the development of new, cost-effective load management and conservation programs. The assessment found GRE's overall program to be quite comprehensive and also provided a useful estimate of the overall potential for energy and capacity savings from various DSM programs.

Because of GRE's currently identified need for peaking power, GRE has put additional attention specifically on programs designed to reduce summer peak demand. GRE's load is dominated by residential customers; thus, the primary driver behind summer peaks is air conditioning load. The best programs to address this need through conservation and demand-side changes are rebates for high efficiency air conditioners and cycled air conditioning. Consequently, GRE has increased its emphasis on these programs. For example, GRE increased its contribution for rebates for residential high-efficiency central air conditioners from $250 to $300. GRE has also increased the rebate to its member cooperatives from $50 to $65 for each new resident participating in the cycled air conditioning program. The increased emphasis on air conditioning programs has also been adopted by GRE's member cooperatives.

For example, one of GRE's largest member cooperatives recently began offering the cycled air conditioning program to its consumers.

In addition, GRE has increased other programs that are shown to be very cost effective and address the types of energy usage most prevalent in the GRE service territory. In 2003, GRE began offering ENERGY STAR Residential Appliance Rebates for clothes washers, dishwashers, and refrigerators. Also, GRE and its member cooperatives award approximately $1 million each year in grants to its commercial and industrial customers for energy efficiency improvement projects. GRE offers a variety of load management and conservation programs and continues to evaluate the impact of additional programs to conserve energy and reduce load. These programs will continue to evolve and shift as the organization's energy needs change.

Despite GRE's increased commitment to conservation, additional conservation is not a practical alternative to the proposed project. First, changes to demand behavior require time to develop. It is unreasonable to think that an additional 170 MW savings during peak usage could be achieved by 2007. Such a change would represent over a 50-percent increase above current programs and participation. Further, successful programs will see diminished increases as the market for participation becomes saturated. Consumer behavior and preferences limit the potential participation in many conservation programs, especially those requiring cut backs at the time of greatest demand. GRE already sees a high percentage of its customers with air conditioners participating in the cycled air program and expects participation numbers to level out. However, GRE's commitment to conservation will not diminish and it will continue to examine its changing energy needs and the potential role of conservation in managing its needs. GRE will always work to design conservation and other demand-side management programs with the goal of maximizing benefits to its members both in terms of overall energy savings and the potential avoided costs of new generation.

4.4 Description of Alternatives

4.4.1 Purchased Power

GRE analyzed the potential alternative of purchased power in two fundamental categories: long-term contracts dedicating specific resources to meet GRE's needs and spot-market purchases. The long-term contract option, through either existing resources or resources to be built specifically to meet GRE's needs, was analyzed using the results from a recent request for proposals (RFP). The option to use spot-market purchases was analyzed based

on recent market experience and market intelligence regarding the expected future availability of this power.

GRE's Corporate Services Division issued a request for proposals (RFP) for a variety of resources in March 2004. 31 proposals from 17 entities were received in response to the Peaking and Intermediate portion of the RFP, including several proposals from GRE's Generation Division. Only five of the 31 bids included the use of existing generating sources. The remaining proposals relied on new generating sources. The RFP review process determined that the GRE self-build option was superior to the other proposals on cost and responsiveness to GRE's needs.

GRE's self-build option has some definite benefits over purchasing capacity and energy from other entities. GRE's status as a cooperative affords it some financial advantages including low-cost financing and lower overhead due to its being a not-for-profit organization. These facts were reflected in GRE's overall proposal price. Purchase power contracts are typically less flexible than desired for a peaking source. Purchases generally require scheduling energy on a day-ahead basis with limited flexibility intraday to respond to unexpected changes in load, availability of other owned resources and the impact of real time transmission availability to support short-term energy purchases. A GRE-owned generation resource can be ramped up and down to follow load and to allow maximizing the dispatch of its other resources.

In addition to long-term contracting of capacity and energy needs typically met through an RFP process, GRE will continue to use spot market purchases to meet its short-term obligations whenever the market is economically competitive. However, GRE's market experience indicates that this type of market purchase is not reliable to meet its current needs for peaking power. GRE's recent experience has been that its energy schedules from spot market purchases are often cut at the highest peak times due to transmission constraints on the grid. While the new MISO market may assist in delivering energy, the transmission constraints will be reflected in the price rather than through cut schedules. Thus, GRE's assessment is that the availability of this type of purchase is unreliable and, if available, would not be as economic as the self-build option

Purchased power is not evaluated further as an option since the RFP analysis and market experience shows it to be less economic and less suitable for meeting GRE's needs than the self-build option.

4.4.2 Upgrades to Existing Resources

Whenever possible, GRE endeavors to undertake capital projects at its legacy generation facilities that add or "free-up" incremental capacity. Over time, GRE has found that it can be less expensive to build incremental capacity at existing facilities rather than developing new resources. That philosophy of adding incremental capacity has been proven in recent history.

4.4.2.1 Historical Upgrades

In the fall of 2001, General Electric (GE) sent notification to GRE recalling the 17th stage compressor blades on each of the six combustion turbines at Lakefield Junction Station. Since the units were being disassembled to replace the recalled equipment, it became economically feasible to engage in a power upgrade project to each of the six units at the same time. The overall efficiency of each unit was improved by 2.2 percent. Further, the capacity of Lakefield Junction was increased by 25 to 30 MW depending on ambient temperature and humidity.

In April 2002, GRE transmission completed significant upgrades to its DC Line and associated converter stations. The MAPP Design Review Subcommittee (DRS) approved the upgrades and granted GRE approval to increase the rating of the DC Line in April, 2003. The rating increase has subsequently allowed GRE to accredit the full net capability of both Coal Creek Station units, adding 32 MW of accredited capacity to GRE's summer and winter capability.

In 2002, the Minnesota Pollution Control Agency and the Minnesota Environmental Quality Board both approved a modification to the air permit at GRE's Saint Bonifacius (St. Boni) peaking plant to allow for operation of that facility above 50 MW. Subsequently, GRE worked with MAPP to determine what transmission upgrades would be necessary for St. Boni to operate above 50 MW. It is anticipated that the transmission upgrades and reconfiguration will be completed by May 2005. As a result of the environmental permit change and transmission work, GRE should realize 6 MW of additional capacity in the summer and 20 MW of additional capacity in the winter at St. Boni.

These examples demonstrate GRE's commitment to continuous analysis of potential upgrades and improvements to its generating facilities.

4.4.2.2 Future Upgrades

There are very few upgrades currently available to existing GRE generating facilities.

GRE has analyzed adding inlet fogging power augmentation to St. Boni. Inlet fogging is a process that adds small water droplets to the inlet air on a combustion turbine; thus, increasing the mass flow into the compressor. It is estimated that inlet fogging could add 4 to 5 MW of additional capacity at less than $100/kW of installed cost. It is likely that GRE will undertake this power upgrade after the transmission constraint outlined in Section 4.4.3 is lifted.

GRE has also considered adding wet compression power augmentation to Pleasant Valley Station units 11 and 12. Wet compression is another process where water droplets are introduced to the compressor inlets; thus, increasing mass flow by cooling the inlet air and adding water mass. It is estimated that wet compression could add 15 to 20 MW of capacity per unit. In order for the upgrade project to be economical, the upgrade would have to be installed along with some other maintenance activity requiring disassembly of the compressors and turbines. This project carries additional risk because it has not been completed on any other turbines of its kind. GRE will monitor whether circumstances arise that make this project reliable and cost effective.

Finally, GRE has also analyzed adding inlet cooling and water injection power augmentation to each of its three oil-fired GE Frame 5 combustion turbines – Cambridge, Maple Lake and Rock Lake. It is estimated that such power upgrades could add 2.7 to 4.3 MW per unit. However, GRE estimates that the power upgrades to those legacy facilities would cost twice as much as adding capacity by building a new combustion turbine. Since it is not cost effective, GRE will not pursue these upgrades at this time.

GRE will continue to analyze all upgrade possibilities. At this time, none of the upgrades in progress or identified for potential future projects are appropriate to meet GRE's immediate needs.

4.4.3 New Transmission

The current environment in the electric industry does not allow transmission lines to be a true alternative to generating resources in most instances. However, new transmission could be considered an alternative if it provided access to existing generating resources in other regions that are currently inaccessible because of the lack of transmission infrastructure. The key obstacle of this alternative is that the existing timelines for planning, permitting and constructing additional transmission would not allow the necessary facilities to be online in a timely manner to meet GRE's immediate needs. In addition, the policies and processes associated with planning and constructing transmission create additional uncertainties.

The planning process for new transmission is done on a regional basis, overseen by a regional authority (the Midwest ISO for this region), rather than being integrated with generation planning within individual utilities. In fact, the process does not directly address transmission as a substitute for generation. In some instances, the transmission planning process might address existing pervasive bottlenecks in the regional bulk transmission system. These have the indirect effect of making existing power elsewhere in the region available to meet GRE's needs.

At any given time, many studies are underway to identify new or upgraded transmission facilities required to deliver the output of possible new generating resources. These studies may identify conditions that indicate that larger or different facilities should be constructed from those required to eliminate the existing bottlenecks, but the construction of such facilities is uncertain as many generating projects do not come to fruition. These factors make accessibility to generating resources hard to precisely identify.

Regulatory uncertainty further complicates this issue. The current methodology for recovering investments in the transmission system generally assigns costs equally to all customers within a transmission zone, with some provisions for direct assignment. This methodology has created barriers to the development of certain types of transmission projects, including many high voltage projects that deliver power across zones or transmission developed for economic rather than purely reliability issues. Industry groups are looking at appropriate methods for identifying benefits and assigning costs but the issue remains very much unresolved.

In addition, major inter-state transmission projects require coordination of permitting and other regulatory approvals in multiple states. While this does not necessarily introduce delay, it could result in longer timelines or risk for a transmission project, particularly if different jurisdictions perceive the benefits differently. Industry groups are also looking to streamline the processes for inter-state activities and reduce risk, but this is in the early stage of development.

Because of the lead time to construct new bulk transmission facilities and regulatory uncertainties, particularly surrounding cost recovery, new transmission lines are not a reasonable alternative to meet GRE's immediate needs and will not be evaluated further.

4.4.4 Other Fossil Fuel Technologies

The following conventional fossil fuel technologies were screened to determine if they meet the primary project objectives:

- Coal-fired technologies including pulverized coal, fluidized bed and gasification combined cycle.
- Oil-fired combustion turbine.
- Natural gas-fired combined cycle.

Coal-Fired Technologies: Coal-fired technologies are usually associated with intermediate and baseload facilities due to their high capital costs and slow start-up times. Operating one of these coal-fired technologies as a peaking facility by keeping them in "stand-by" mode greatly reduces their efficiency and increases emissions. Further, it increases the wear and tear on the equipment, which can lead to more frequent forced and planned outages.

Siting and permitting of a new coal-based power plant in Minnesota would likely be a lengthy process. This process, along with the additional time needed to construct a coal-based facility, would push the availability of the capacity past the summer 2007 time frame needed to satisfy one of the project's primary objectives. The earliest any of the coal-based projects currently under development could be on line is 2011.

Coal-fired technologies fail to meet the primary objectives due to the lengthy time needed to site, permit and construct them as well as inappropriate operating characteristics. Therefore, coal-based projects will not be considered for further evaluation.

Oil-Fired Combustion Turbine (simple cycle): This alternative is similar to the proposed project except No. 2 fuel oil would be the primary fuel. No back-up fuel would be needed since on-site oil storage tanks would be used to provide the necessary run time. The same or largely similar units as described in Section 3 would be utilized. Because of the similarities between this alternative and the proposed project, this alternative meets the first two primary objectives for the project.

Since the need to be near an adequate gas supply would no longer be a concern, siting this type of unit is simplified but emissions would be more of a concern. Burning fuel oil would result in higher emissions of sulfur dioxide, carbon monoxide and nitrogen oxides than a natural gas-fired alternative. Table 4-3 summarizes the other major operational differences between this alternative and GRE's project.

Using oil for fuel results in higher operating costs than a natural gas-fired alternative. Higher operating costs mean this alternative would not run as much, limiting the opportunities to provide ancillary services such as load following and regulation while operating.

Because this alternative meets the first two primary screening objectives, it will be evaluated further in Section 4.5.

Combined Cycle: The combined cycle plant requires a 24-month construction period. The associated permitting and longer construction time-frame makes commercial operation by summer 2007 unachievable.

The combined cycle technology is generally not considered for peaking service due to higher capital and fixed O&M costs compared with simple

cycle technology. In addition, the combined cycle plant is not suited for service requiring fast starts and short operation schedules.

Because this alternative does not meet the first two primary screening objectives, it will not be evaluated further in Section 4.5.

4.4.5 New Customer-Owned Generation

Several of GRE's member systems have very actively promoted installing customer-owned generation ("distributed generation"). Approximately 116 MW of customer-owned generation are already in place and 17 MW of additional customer-owned generation is expected to be in place by 2006. The 116 MW represents the capacity benefit from these generators in the summer season. This is an appropriate benchmark for inclusion since GRE's system peaks in the summer. It should be noted that if these generators are utilized in other seasons, the benefit would be one half or one third as large, because a lot of the load being replaced by running these generators is commercial air conditioning.

The distributed generation is utilized to serve loads that are interrupted from the system. This type of use results in the peak reduction of the MW of avoided capacity amount plus 15 percent. This is because each MW of peak load demand requires 15 percent more capacity because of the MAPP reserve sharing agreement and the distributed generation reduces the peak load and all of its requirements. If the generation is accredited by MAPP and operated in parallel to the system, the 15 percent adjustment would not apply.

While the peak reduction is an attractive characteristic of these resources, the emissions are more of a concern. The small size of the distributed generation units allows them to be subject to less stringent air emission requirements, resulting in higher total emissions than larger alternatives, which are subject to more stringent air emission restrictions. Further, it is unrealistic to expect that enough generators could be installed in a time frame to satisfy GRE's current needs. In addition to the already planned distributed generation, it would require more than 70 diesel engine generator sets of two MW to be installed to meet GRE's 2007 needs. This is not feasible due to the large number of sites involved and the associated infrastructure needs for each site.

Because this alternative does not meet the first two primary screening objectives it will not be evaluated further in Section 4.5.

4.4.6 Emerging Technologies

There are a number of emerging technologies that have the potential to dramatically impact how electricity is produced, delivered and used. Many of these technologies are small enough to be located very close to the point of consumption, minimizing the need for new transmission and distribution. These technologies include:

- Fuel Cells.
- Micro Turbines.
- Energy Storage (such as batteries, pumped storage hydro, compressed air energy storage, and super conducting magnetic energy storage).

Fuel Cells: Fuel cells convert hydrogen rich fuels directly to electricity through electrochemical reactions. The reactants, fuel and oxidant (air or oxygen) are fed to separate anode and cathode electrodes. Electricity is generated by the transport of ions generated by the anode reaction across the electrolyte separating the anode and cathode. Because this is not a combustion process, there are no air emissions other than water vapor and carbon dioxide. Fuel cells are very efficient, even in small plant sizes.

Phosphoric acid fuel cells (PAFC) are currently available in 200-kW unit sizes. Their cost is in excess of $2000/kW, making them uneconomical. Molten carbonate (MCFC) and solid oxide fuel cells (SOFC) are not yet commercially available although the developers are hopeful they will become available in the next several years. Proton exchange membrane (PEM) fuel cells have created interest recently, primarily for automotive and transit applications. They are also under development for stationary power applications but are not yet commercially available.

While there is much interest in fuel cells and great expectations for commercial availability of various fuel cells, it is unreasonable to expect them to be available in sufficient quantity to meet the identified need by 2007. Most fuel cells are also baseload in nature and would not be cost effective at the low

capacity factors typical of a peaking resource. Therefore, this technology will not be considered for further analysis.

Micro-turbines: Micro-turbines are small combustion turbines with capacities in the range of 30 to 250 kW. Micro-turbines are well suited for distributed generation applications. The units are small and relatively efficient for their size. Installed costs range from $450 to $700 per kW and efficiencies range from 22 percent to 30 percent. Micro-turbines for distributed generation are being developed by several potential vendors. These units have a single shaft with the generator, air compressor and turbine mounted on air bearings to eliminate the need for bearing lubrication. Power electronics convert the high frequency AC current from the generator to DC current. An inverter then converts the DC current to AC current at a standard distribution voltage. Due to the small size of the units, they can be online in a relatively short time and can be mounted on a pole, platform, in a substation, on a roof, in a vault or on a pad.

Micro-turbines are a rapidly developing technology. Although long term reliability is projected to be good, micro-turbines are not in commercial use at this time and, therefore, their reliability has not been demonstrated in real world applications. There is considerable uncertainty on the long-term O&M costs and operating life for this technology. Because micro-turbines are not commercially proven at this time, they were not selected for further evaluation.

Energy Storage: Energy storage can be used to dampen out fluctuations in the demand for electrical energy. It also allows for the possibility that electricity can be generated at low cost at times of low demand and then retrieved from storage during periods of high demand. Energy storage options include:

- Batteries.
- Pumped storage.
- Compressed air.
- Superconducting magnets.

Batteries: Batteries are well known for their ability to store electrical energy. Batteries represent a resource option for electric utilities but lead acid batteries, the most common type used for storage in larger scale applications, have a limited life (1500 to 2000 charge-discharge cycles) and are expensive. Advanced batteries are being developed that may increase the cycle life and lower costs.

As a result of the high cost of this option and limited experience in the use of batteries in utility-sized applications, this option was not considered for further evaluation.

Pumped Storage Hydro: Pumped storage hydro refers to an energy storage technology where water is pumped to a high reservoir during off-peak hours and released to generate electricity during on-peak hours. This is a mature technology. A primary problem with pumped hydro is locating suitable sites. Minnesota state law prohibits the use of the Mississippi river as a water source for pumped storage facilities.

Because no suitable sites were identified, this option was not considered for further evaluation.

Compressed Air: With this option, electricity is used during off-peak periods to compress air in underground caverns or porous rock reservoirs. During on-peak periods, the stored air can be released to provide compressed air for the combustion portion of a combustion turbine.

This is an immature technology and existing prototype plants have not performed to expectations. Therefore compressed air was not considered for further evaluation.

Superconducting Magnets: A superconducting magnet refers to a coil that can store electrical energy. Because the coil is superconducting, storage losses are very low. This is an emerging technology that is not fully developed and it was not considered for further evaluation.

None of these emerging technologies are reasonable alternatives based on either the immature state of their development or their being inappropriate for peaking applications at this time.

4.4.7 Summary of Preliminary Evaluation

The following table summarizes the conclusions reached in the preceding descriptions of the alternatives with respect to the primary project objectives. It indicates those alternatives that have been screened for further consideration.

Table 4-2 shows three alternatives passed the primary screening for further evaluation. These alternatives are all combustion turbine peaking plants, using three different fuel sources: natural gas (the proposed project), fuel oil and ethanol. Table 4-3 shows the operating characteristics of the proposed project and two alternatives. Additional economic analysis will be addressed in the following section.

Table 4-2 - Summary of Alternatives

Primary Objectives			
Alternative	**170 MW Available for 2007**	**Suitable Operating Characteristics**	**Considered in further Economic Screening**
DSM	No	No	No
Renewables			
Wind	No	No	No
Biomass	No	No	No
Ethanol-fired combustion turbine	Yes	Yes	Yes
Hydro	No	No	No
Solar	No	No	No
Purchased Power – Market	Unlikely	Yes	No
Purchased Power – Built for GRE	Yes	No	No
Upgrades to Existing Resources	No	No	No
New Transmission	No	No	No
Coal	No	No	No
Oil-fired combustion turbine	Yes	Yes	Yes
Combined cycle	No	No	No
DG/Customer Owned	No	Maybe	No
Emerging Technologies			
Micro turbines	No	No	No
Fuel cells	No	No	No
Energy Storage			
Batteries	No	Yes	No
Pumped Storage Hydro	No	Yes	No
Compressed Air Energy Storage	No	Yes	No
Super Conducting Magnetic Energy Storage	No	Yes	No

Table 4-3 – Alternatives' Operational Characteristics

Characteristic	Project	Oil-Fired Simple-Cycle	Ethanol-Fired Simple-Cycle	MN Rule
Facility Description				
Unit Type	F-Class	F-Class	F-Class	
Prime Mover	Combustion Turbine	Combustion Turbine	Combustion Turbine	
Number of Units	1	1	1	
Summer Capability (site specific)[1]	170 MW	164 MW	164 MW	7849.0250, A(1)
Winter Capability (site specific)	190 MW	190 MW	190 MW	7849.0250, A(1)
Operating Cycle	Simple-cycle	Simple-cycle	Simple-cycle	7849.0250, A(2)
Expected Annual Capacity Factor	9.6%	9.6%	9.6%	7849.0250, A(2)
Expected Heat Rate/Efficiency (Summer site specific)[2]	10,200 Btu/kWh (HHV)/35%	10,450 Btu/kWh (HHV)/34.6%	10,450 Btu/kWh (HHV)/34.6%	7849.0250, A(4)
Expected Heat Rate/Efficiency (Winter site specific)[2]	9,730 Btu/kWh (HHV)/37%	9,900 Btu/kWh (HHV)/36.5%	9,900 Btu/kWh (HHV)/36.5%	7849.0250, A(4)
Heat Rejected through exhaust (Summer)	1,013 MMBtu/hr	1,061 MMBtu/hr	1,061 MMBtu/hr	
Heat Rejected through exhaust (Winter)	1,188 MMBtu/hr	1,224 MMBtu/hr	1,224 MMBtu/hr	
Fuel Description				
Fuel Source: Natural Gas only	Northern Natural Gas Pipeline	Regional Refineries	Regional Ethanol Plants	7849.0320, C(1)
Fuel Requirement: (Summer)[2]	1,546 MCf/hr	12,695 gal/hr	22,550 gal/hr	7849.0320, C(2)
Fuel Requirement: (Winter)[2]	1,771 MCf/hr	13,933 gal/hr	24,750 gal/hr	7849.0320, C(2)
Expected Annual Fuel Requirement	1,305,360	11,109,511 gal/yr	19,734,000 gal/yr	7849.0320, C(2)
Heat Input (Summer - HHV)[2]	1554 MMBtu/hr	1,714 MMBtu/hr	1,714 MMBtu/hr	7849.0320, C(3)
Heat Input (Winter - HHV)[2]	1780 MMBtu/hr	1,881 MMBtu/hr	1,881 MMBtu/hr	7849.0320, C(3)
Fuel Heat Content	1.005 MMBtu/MCf	0.137 MMBTU/gal	0.0841 MMBTU/gal	7849.0320, C(4)
Fuel Sulfur Content	5.5 mg/m^3	<0.05 percent	Unknown	7849.0320, C(5)
Fuel Ash Content	None	Trace	Unknown	7849.0320, C(5)
Fuel Moisture Content	<80 mg/m^3	Trace	Unknown	7849.0320, C(5)
Water Use				
Estimated maximum groundwater pumping rate[3]	108 gpm	454 gpm	611 gpm	7849.0320, E(1)
Estimated maximum surface water appropriation[3]	0 ft^3/sec	0 ft^3/sec	0 ft^3/sec	7849.0320, E(1)
Estimated annual groundwater appropriation[4]	3. million gal/yr	13 million gal/yr	17 million gal/yr	7849.0320, E(2)
Annual consumption[4]	9.2 acre-feet	38.6 acre-feet	52.0 acre-feet	7849.0320, E(3)
Discharges to water	2.1 million gal/yr	2.1 million gal/yr	2.1 million gal/yr	
Estimated Emission Rates (lbs/hr)				
CO [2]	37	47	47 [5]	7849.0320, D(1)
SO_2 [2]	5.7	91	91 [5]	7849.0320, D(1)
NO_x [2]	169	327	327 [5]	7849.0320, D(1)
PM_{10} [2]	15	36	36 [5]	7849.0320, D(1)
Other Information				
Land Requirements	2.5 acres	2.5 acres	2.5 acres	
Traffic	Slight increase due to on-site operators	Increased due to fuel deliveries	Increased due to fuel deliveries	
Radioactive Releases	None	None	None	
Solid Wastes Produced	Construction packaging, office waste, waste lubricating oils	Construction packaging, office waste, waste lubricating oils	Construction packaging, office waste, waste lubricating oils	
Noise	≤ 63 dB(A) @ 400 ft.	≤ 63 dB(A) @ 400 ft.	≤ 63 dB(A) @ 400 ft.	
Work Force	2 to 3 FTE	2 to 3 FTE	2 to 3 FTE	
Transmission Requirements	Upgrade 3 sections of 69-kV lines	Upgrade 3 sections of 69-kV lines	Upgrade 3 sections of 69-kV lines	

1 With evaporative cooler in service.
2 Under base load operations.
3 When unit is on-line.
4 Assuming a 9.6% annual capacity factor and utilization of evapoartive cooler for 5.7% of annual operation.
5 Emissions estimates are typically based on operating data from other units in operation. No ethanol-fired combustion turbines are in operation and no manufacturers have tested ethanol-fired turbines. Therefore, emissions are assumed to be equivalent to those from firing fuel oil.

4.5 Economic Comparisons to Proposed project

Table 4-4 provides the cost comparison between the project and the alternatives, which have met the initial screening criteria (oil-fired combustion turbine and the ethanol-fired combustion turbine). This table shows that the proposed project is clearly the lowest-cost alternative.

Table 4-4 - Comparison of Peaking Alternatives – Cost of Electricity

Item	Units	Project	Oil-Fired Simple-Cycle	Ethanol-Fired Simple-Cycle	Assumptions	MN Rule
Project Description						
Base Capability (Summer, site-specific rating)	MW	170	164	164	Manufacturer *pro forma* estimate	7849.025, A(1)
Cost Basis	Cal Yr	2004	2004	2004		
Life of Project	Years	30	30	30	Typical accounting life	7849.025, C(2)
Operating Cycle		Simple	Simple	Simple		7849.025, A(2)
Annual Capacity Factor	%	9.6%	9.6%	9.6%	PVS experience	7849.025, A(2)
Annual Operating Time	Hours	840	840	840	Formula	
Average Annual Availability	%	97.5	97.5	97.5	PVS ops experience	7849.025, C(3)
Fuel Type		Nat Gas	No. 2 Fuel Oil	Ethanol		7849.025, A(3)
Heat Input (HHV)	MMBtu/hr	1,554	1,714	1,714	PVS ops experience	
Heat Rate (HHV) - Summer Rating	Btu/kWh	10,200	10,450	10,450	PVS ops experience	7849.025, A(4)
Efficiency (HHV) - Summer Rating	%	35.4	34.6	34.6	Formula	7849.025, C(8)
Project Capital Cost	$/kW	406	430	443	Overnight cost w/o IDC	
Fixed O&M Costs	$/kW-yr	3.46	3.46	3.46	PVS experience	
Fuel Costs	$/MMBtu	5.73	7.45	20.22	EIA *2005 AEO* plus transport & balancing	7849.025, C(4)
Non-Fuel Variable O&M Costs	$/MWh	8.41	12.62	12.62	Includes fired-hour costs & start charge	7849.025, C(5)
Capacity Costs (Fixed)						**7849.025, C(1)**
Total Project Capital Cost	$	69,020,000	70,520,000	72,652,000	Formula	
Annual Fixed O&M	$	588,200	567,440	567,440	Formula	
Total Annual Fixed Costs	$	6,523,920	6,632,160	6,815,512	8.6% annual FCs + Fixed O&M	
Project Capacity Cost	$/kW-yr	38.38	40.44	41.56	Formula	
Project Capacity Cost	$/kWh	0.046	0.048	0.049	Formula	
Production Costs (Variable)						
Net Annual Generation	MWh	142,800	137,760	137,760	Formula	
Annual Fuel Consumption	MMBtu	1,305,360	1,439,760	1,439,760	Formula	
Annual Fuel Cost	$	7,483,015	10,728,673	29,111,947	Formula	
Annual Non-Fuel Variable O&M Cost	$	1,200,948	1,738,531	1,738,531	Formula	
Total Project Variable Generation Cost	$	8,683,963	12,467,204	30,850,478	Formula	
Project Fuel Cost	$/kWh	0.052	0.078	0.211	Formula	7849.025, C(4)
Project Total Energy Cost	$/kWh	0.061	0.090	0.224	Formula	
Total Cost	**$/kWh**	**0.106**	**0.139**	**0.273**	**Formula**	**7849.025, C(6)**

As for the biomass alternative analyzed, the table shows that substantial reductions in the cost of ethanol would be needed in order for such an alternative to be competitive with the project. Therefore, an ethanol-fueled peaker is not a reasonable alternative

Table 4-5 below demonstrates the relative annual revenue requirement ($/MWh) for the three projects examined in depth in Table 4-3 and 4-4. This includes the proposed project as well as two alternatives.

Table 4-5 – Comparison of Peaking Alternatives - Rate Impact

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

4.6 Conclusion

GRE has examined alternatives to the proposed project. Based on the primary objectives, there are no reasonable alternatives that are available in the necessary timeframe that would reliably and economically meet GRE's peaking resource needs.

5 CONSEQUENCES OF DELAY

Delaying construction of the proposed facilities could have significant negative consequences for GRE and the region, including rising costs, difficulty in meeting capacity obligations, increased use of existing peaking facilities and reduced electric system reliability.

If the project is not constructed, GRE's costs would increase because more expensive alternative resources would need to be utilized to meet capacity and energy needs. These higher costs would in turn result in higher rates for GRE's members. The specific impact would depend on the length of the delay. If the project were delayed one to two years, GRE would purchase short-term capacity to cover its deficit. The cost of short-term capacity are usually not known until closer to the specified season and depend on factors such as weather forecasts, known outages in the region and other market conditions. If construction were delayed two to three years or indefinitely, GRE would need to purchase long-term capacity at prices that are expected, based on GRE's recent RFPs, to be higher than the cost of the proposed project.

In the event of a delay, GRE would also attempt to meet its needs through increased use of existing facilities. GRE's existing baseload generation facilities are currently running at or close to full capacity and therefore could be utilized to meet this need. GRE's existing natural gas and oil-fired peaking facilities would need to be dispatched more frequently, resulting in higher fuel costs and increased emissions. The increased fuel costs and emissions would result from the fact that the project would be more efficient than any of GRE's current peaking facilities. However, these peaking resources could only help to replace energy needs. These resources could not meet GRE's capacity needs as GRE currently utilizes all of its existing facilities to meet its current capacity obligations.

A delay could also result in GRE not having enough capacity to meet its MAPP peak load obligation. MAPP requires that members maintain 15 percent more capacity than their peak load to ensure regional electric system reliability. MAPP requires any utility not meeting this requirement to purchase capacity at $45,000 – 90,000 MW of deficit. A 100 MW deficit would result in a penalty of $4.5 – 9.0 million for each season in which this occurs, which would most likely be summer only.

Electric system reliability is extremely complex and is dependent upon adequate generation and transmission capacity. GRE's neighboring systems and other pool members could experience lower reliability if this project were delayed. Conversely, additional generation capacity could improve system reliability.

In evaluating the changes in resource requirements if the facility were not constructed, GRE assumed that the needed energy and capacity would be provided, presumable by a third party.

The amount of land required would not change because GRE already owns the land on which the project would be located.

The amount of induced traffic would be reduced, primarily by avoiding construction, and as a result of eliminating the two to three employees who would otherwise have operated the facility.

The fuel requirements listed in Section 3 of this application would be eliminated, except that the other facilities operated to replace the lost energy and capacity would necessarily have their own fuel requirements. Because the proposed facility is one of the most efficient peaking facilities in this region, it is likely that an incrementally greater amount of fuel would be required to replace the amount of energy and capacity.

The airborne emissions listed in Section 3 of this application would be eliminated. Those emissions are not significant. The other facilities operated to replace the lost energy and capacity would likely have slightly higher emission due to the fact that the proposed facility is one of the most efficient peaking facilities in this region.

The water appropriations and discharges listed in Section 3 of this application would be eliminated. However, the facilities used to replace the capacity and energy would likely have their own water requirements and impacts. It is not possible to provide an estimate of the comparative consequences.

The rejected heat listed in Section 3 of this application would be eliminated. The other facilities operated to replace the lost energy and capacity would likely have higher rejected heat due to the fact that the proposed facility is one of the most efficient peaking facilities in this region.

The minimal amount of solid waste described in Section 3 of this application would be avoided. Presumably the alternative facilities used ot replace the lost energy and capacity would create other solid waste.

The noise listed in Section 3 of this application would be eliminated. That noise is not likely perceptible above existing and background noise levels to the nearest residences. The other facilities operated to replace the lost energy and capacity would result in some additional noise.

The two to three individuals who would have operated the facility would not be needed. Also the approximately 100 skilled craft workers who would have constructed the facility would not be needed. It is unknown whether the alternative facilities used to replace the lost capacity and energy would result in additional labor requirements.

GRE has not identified any equipment or measures that could be used to reduce the environmental impact of the alternative of no facility.

6 CONCLUSIONS

6.1 The project is needed and denial would adversely impact reliability and efficiency of energy supply for GRE, its customers and the people of Minnesota

Denial of this application would adversely impact GRE's ability to reliably serve its cooperative members at a reasonable cost. GRE's members serve suburban and rural customers across approximately two-thirds of the geographic region of Minnesota.

The need for the project is based on forecasted load growth. GRE has been a fast growing utility and such growth is projected to continue for the foreseeable future. This project will satisfy GRE's peaking resource needs for the year 2007 and continue to meet GRE's needs in the years beyond 2007. After 2007, GRE's continued growth will require new resources in addition to this project. Denial of this project would establish an ongoing deficit, making it increasingly difficult for GRE to meet its members' needs.

6.2 There is no more reasonable and prudent alternative to the project

GRE's current need is for peaking power. As demonstrated in section 4, there are not many alternative resources appropriately suited for peaking. The project is the appropriate type of resource to cover peak demands as well as a small portion of energy requirements. Conventional combined cycle and baseload resources are not economical when operated at the low capacity factors expected for peaking resources. Renewable resources, including wind, wood, hydro, solar and geothermal, are all energy producing resources which do not effectively cover peak demands. They also do not compete economically at the low capacity factor associated with peaking resources.

GRE has a long history of cost-effective conservation programs, which have delayed the need for peaking capacity projects such as this one. Conservation programs will continue to be utilized but cannot reduce peak demands in the immediate future enough to eliminate the need for the proposed project. GRE is also constantly analyzing its existing generation resources and pursuing all cost-effective upgrades. Further upgrades would not meet the needs identified in this filing.

6.3 The project will provide benefits to society compatible with the natural and socioeconomic environments

The project is expected to provide needed capacity and energy resources for GRE's member cooperatives as well as the state and region.

The project is both economically and environmentally attractive. The project utilizes a clean fuel, low-emitting combustion technology, and an existing site, all of which minimize its impact on the surrounding environment. The project is also being sited to minimize the construction of gas pipeline and transmission line.

The increased need for generating capacity in the GRE system results from strong regional economic growth over the past decade. The rural and suburban service territory of GRE's cooperative members will benefit from the project. The project will help GRE's cooperative members continue to supply reliable power at a low cost to their customers. Low cost electricity is an important component in supporting stable economic growth in the region.

6.4 The project will comply with all applicable local, state and federal requirements

Consistent with GRE's overall business philosophy, this project will be carried out in a manner compatible with all local, state, and federal rules, laws and policies applicable to the project.

APPENDIX A FORECAST

This appendix provides the details and methodology of Great River Energy's load forecast. As described in Section 2, GRE used its 2002 Long Range Load Forecast ("2002 load forecast" or "2002 LRLF").

Great River Energy provides service to 28 member systems. One of these member systems has a small amount of service territory in Wisconsin. However, the sales to Wisconsin is less the one-tenth of one percent of GRE's total energy sales and therefore have been rounded to zero for the purposes of this application. Thus, all energy consumption of Great River Energy members is reported here as Minnesota sales.

A.1 Consumers and Annual Consumption

The following table itemizes data concerning ultimate consumers. GRE serves no mining loads or electrified transportation.

Table A-1 – Consumers by Customer Class

Historical Consumers										
	Farm	Non-farm	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Total
1992	44,631	361,109	1,842	20,401	193	0	1,863	0	403	430,442
1993	45,760	370,236	1,875	20,978	203	0	1,945	0	403	441,400
1994	46,988	380,178	1,941	21,683	213	0	2,003	0	406	453,412
1995	48,160	389,661	2,019	22,236	225	0	2,056	0	407	464,764
1996	49,342	399,220	2,125	23,035	265	0	2,150	0	406	476,543
1997	50,414	407,896	2,205	25,047	336	0	2,245	0	477	488,620
1998	51,453	416,302	2,296	26,856	350	0	2,344	0	486	500,088
1999	52,744	426,747	2,357	28,166	363	0	2,406	0	494	513,277
2000	54,157	438,181	2,439	29,477	376	0	2,547	0	587	527,764
2001	55,442	448,575	2,486	30,911	397	0	2,687	0	503	541,001
Forecast Consumers										
	Farm	Non-farm	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Total
2002	56,943	460,725	2,518	32,082	410	0	2,771	0	505	555,954
2003	58,471	473,080	2,553	33,030	425	1	2,924	1	506	570,991
2004	60,003	485,479	2,586	33,934	438	2	3,048	2	508	585,999
2005	61,537	497,893	2,620	34,844	450	3	3,173	3	509	601,032
2006	63,019	509,884	2,654	35,749	464	4	3,252	4	511	615,541
2007	64,465	521,579	2,688	36,642	473	5	3,331	5	512	629,700
2008	65,913	533,299	2,721	37,544	486	6	3,412	6	514	643,902
2009	67,365	545,043	2,756	38,449	498	7	3,492	7	515	658,132
2010	68,821	556,822	2,789	39,362	511	8	3,571	8	517	672,408
2011	70,280	568,627	2,824	40,276	521	9	3,652	9	518	686,715
2012	71,744	580,470	2,852	41,202	534	10	3,731	10	520	701,073
2013	73,210	592,335	2,881	42,136	545	11	3,811	11	521	715,461
2014	74,677	604,207	2,909	43,068	557	12	3,892	12	523	729,858
2015	76,149	616,115	2,938	44,010	568	13	3,971	13	524	744,300
2016	77,619	628,009	2,967	44,953	580	14	4,050	14	526	758,732
2017	79,091	639,918	2,996	45,906	591	15	4,129	15	527	773,187
2018	80,563	651,829	3,025	46,866	603	16	4,210	16	529	787,657
2019	82,034	663,733	3,054	47,829	614	17	4,290	17	530	802,118
2020	83,509	675,663	3,082	48,806	623	18	4,369	18	532	816,621
2021	84,985	687,607	3,112	49,796	635	19	4,450	19	533	831,157

Annual electrical consumption within GRE's system is reported in the following table.

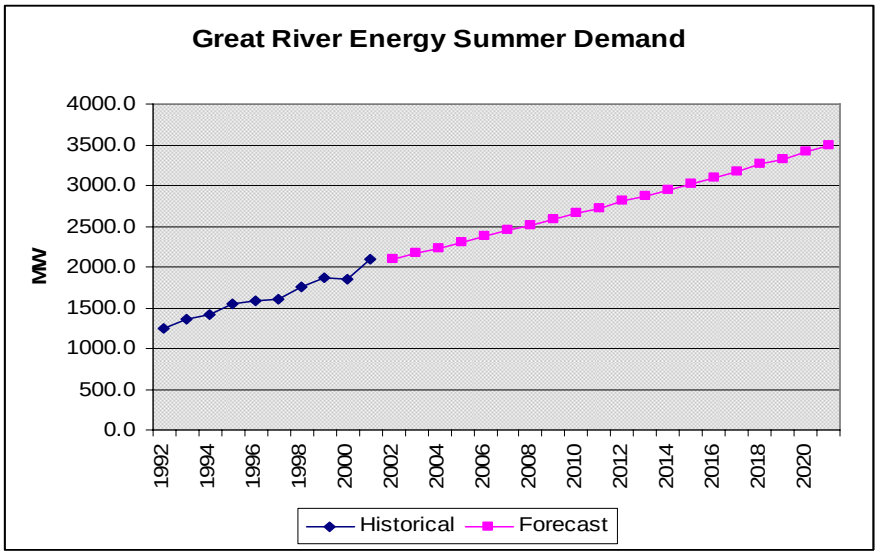
Table A-2 – Consumption by Customer Class

Historical Energy (MWh)													
	Farm	Non-farm	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Sales for Resale	Members' Own Use	Losses	Total
1992	446,852	3,615,436	36,352	1,133,463	592,405	0	16,008	0	9,135	107,903	10,850	1,253,039	7,221,443
1993	471,988	3,818,816	14,137	1,204,899	639,192	0	15,140	0	8,338	115,249	11,674	1,190,689	7,490,122
1994	488,830	3,955,075	33,727	1,297,134	680,555	0	17,756	0	8,800	124,158	12,914	1,330,707	7,949,656
1995	515,983	4,174,771	31,102	1,409,557	717,737	0	19,181	0	9,100	143,731	14,280	1,401,064	8,436,506
1996	535,023	4,328,825	49,456	1,508,497	792,613	0	19,954	0	10,255	155,501	15,304	1,524,739	8,940,167
1997	528,927	4,279,501	28,837	1,624,273	874,143	0	20,770	0	9,742	163,427	18,961	1,301,585	8,850,166
1998	541,474	4,381,016	46,427	1,790,199	927,912	0	22,583	0	10,387	175,419	17,124	1,313,762	9,226,304
1999	572,633	4,633,122	37,951	1,915,289	956,915	0	22,843	0	9,927	177,684	21,132	1,153,504	9,500,999
2000	596,504	4,826,257	51,344	2,033,559	1,090,629	0	23,507	0	11,224	175,915	21,136	454,395	9,284,470
2001	617,016	4,992,218	62,114	2,116,808	1,161,838	0	24,023	0	11,301	188,405	21,140	992,436	10,187,300
Forecast Energy (MWh)													
	Farm	Non-farm	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Sales for Resale	Members' Own Use	Losses	Total
2002	634,056	5,130,086	47,450	2,217,674	1,090,629	0	24,219	0	11,224	181,381	21,132	1,401,726	10,759,577
2003	651,244	5,269,153	48,213	2,300,988	1,161,838	0	24,947	0	11,301	183,776	21,136	1,433,681	11,106,278
2004	670,138	5,422,028	48,931	2,382,690	1,222,861	0	25,567	0	11,386	186,171	21,140	1,466,185	11,457,097
2005	689,362	5,577,569	49,673	2,467,535	1,278,513	0	26,232	0	11,463	188,566	21,168	1,497,474	11,807,555
2006	708,130	5,729,416	50,426	2,551,248	1,337,956	0	26,838	0	11,548	190,961	21,172	1,529,921	12,157,615
2007	726,581	5,878,704	51,169	2,637,541	1,352,427	0	27,448	0	11,625	193,356	21,176	1,557,152	12,457,179
2008	745,145	6,028,899	51,890	2,725,928	1,389,220	0	28,068	0	11,710	195,751	21,180	1,586,869	12,784,660
2009	763,649	6,178,613	52,658	2,813,474	1,416,692	0	28,688	0	11,787	198,146	21,184	1,615,481	13,100,371
2010	782,354	6,329,959	53,380	2,902,647	1,446,575	0	29,310	0	11,872	200,541	21,188	1,644,756	13,422,582
2011	801,210	6,482,514	54,143	2,992,853	1,465,546	0	29,956	0	11,949	202,936	21,192	1,673,270	13,735,569
2012	820,458	6,638,247	54,785	3,088,165	1,512,765	0	30,586	0	12,034	205,331	21,196	1,705,579	14,089,146
2013	839,657	6,793,589	55,452	3,185,345	1,527,116	0	31,221	0	12,111	207,726	21,200	1,734,534	14,407,952
2014	859,070	6,950,658	56,096	3,282,871	1,556,879	0	31,866	0	12,196	210,121	21,204	1,765,297	14,746,258
2015	878,520	7,108,029	56,764	3,380,823	1,571,231	0	32,507	0	12,273	212,516	21,208	1,794,549	15,068,420
2016	898,001	7,265,647	57,433	3,479,233	1,607,904	0	33,153	0	12,358	214,911	21,212	1,826,046	15,415,898
2017	917,511	7,423,495	58,103	3,578,807	1,626,755	0	33,802	0	12,435	217,306	21,216	1,856,041	15,745,471
2018	937,053	7,581,614	58,766	3,678,883	1,656,518	1	34,462	1	12,520	219,701	21,220	1,887,122	16,087,861
2019	956,679	7,740,399	59,437	3,781,081	1,670,870	2	35,121	2	12,597	222,096	21,224	1,916,953	16,416,460
2020	976,474	7,900,558	60,086	3,885,119	1,694,464	3	35,783	3	12,682	224,491	21,228	1,947,997	16,758,888
2021	996,327	8,061,190	60,782	3,991,397	1,708,816	4	36,455	4	12,759	226,886	21,232	1,978,443	17,094,295

A.2 Peak Demand

Great River Energy has been a summer peaking system since 1987. Figure A-1 shows GRE's forecasted demand at the level used for planning purposes. This is scenario 5, as described below, and has also been referred to as the high probability demand scenario in Section 2 of this application.

Figure A-1 – Great River Energy Summer Demand



A.2.1 Summer Demand Scenarios

GRE developed five scenarios for its forecasted demand analysis.

1) Most probable economic assumptions, with normal weather.
2) Most probable economic assumptions, with severe weather causing higher loads.
3) Most probable economic assumptions, with mild weather causing lower loads.
4) Normal weather with more pessimistic macroeconomics assumptions causing lower loads.
5) Normal weather with more optimistic macroeconomics assumptions causing higher loads.

Scenario 1 is the base case reported in the 2002 LRLF. This forecast does not reflect the highest possible load. Factors such as weather and the economy will cause fluctuations around the base case level.

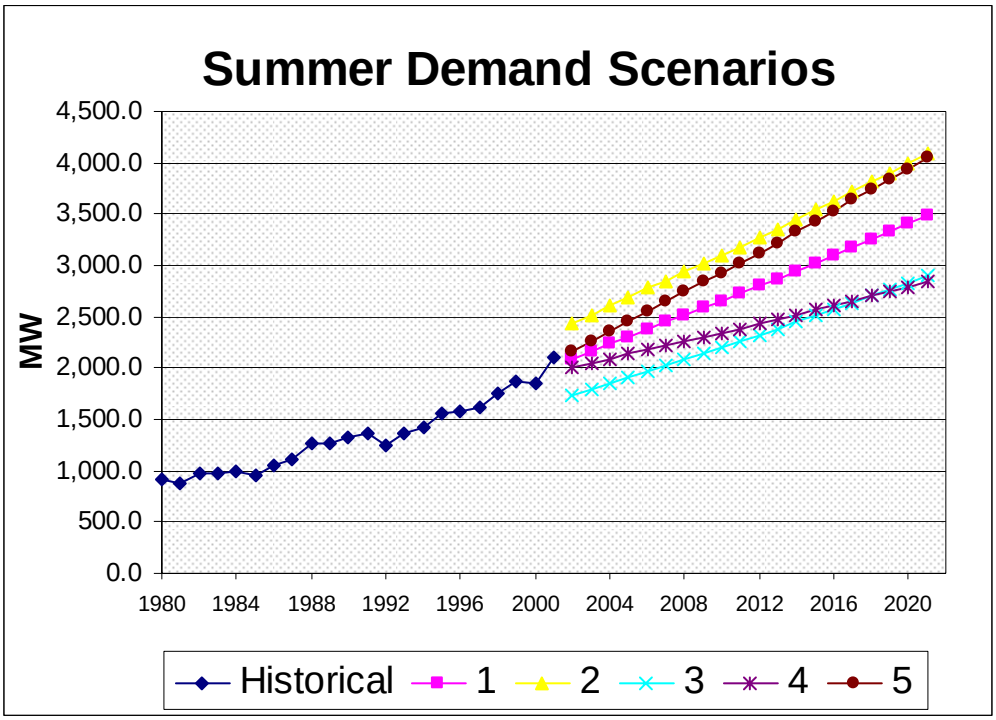
Scenarios 4 and 5, which reflect the effects of varying economic activity, were calculated by assuming 60 percent and 135 percent of forecast growth. These

levels were selected after examining the historical effect of recessions and examining the potential for future variations in growths. For purposes of planning capacity to meet reliability requirements, GRE used Scenario 5 to determine capacity deficits over the planning horizon.

As the base case, Scenario 1 is the central tendency forecast. This forecast will be exceeded one-half of the time. As a load serving entity, GRE is obligated to serve every megawatt demanded. As such, we must plan to serve at a high level of probability, not the average level. Being unable to serve demand half of the time (as would be predicted under Scenario 1) is unacceptable. GRE considers Scenario 5 as capturing most of the risk of faster growth due to a booming economy. GRE's analysis shows that Scenario 5 would capture actual demand approximately 90 percent of the time, making it somewhat analogous to a 90 percent confidence interval scenario. GRE has determined that planning to this level of certainty is more prudent and reflects a level of risk acceptable to our members.

Figure A-2 reflects these scenarios. The legend corresponds to the previous description.

Figure A-2 – Summer Demand Scenarios



A.2.2 Peak Demand by Consumer Categories

Table A-3 – Peak Demand by Consumer Categories Based on Scenario 5

Historical Demand (MW)													
	Farm	Non-farm	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Sales for Resale	Members' Own Use	Losses	Total
1992	78	627	6	197	103	0	3	0	2	19	2	217	1,253
1993	86	693	3	219	116	0	3	0	2	21	2	216	1,360
1994	87	705	6	231	121	0	3	0	2	22	2	237	1,416
1995	95	768	6	259	132	0	4	0	2	26	3	258	1,553
1996	95	765	9	266	140	0	4	0	2	27	3	269	1,579
1997	96	778	5	295	159	0	4	0	2	30	3	237	1,610
1998	103	830	9	339	176	0	4	0	2	33	3	249	1,748
1999	113	914	7	378	189	0	5	0	2	35	4	228	1,875
2000	119	964	10	406	218	0	5	0	2	35	4	91	1,854
2001	127	1,026	13	435	239	0	5	0	2	39	4	204	2,094
Forecast Demand (MW)													
	Farm	Non-farm	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Sales for Resale	Members' Own Use	Losses	Total
2002	128	1,032	10	446	219	0	5	0	2	36	4	282	2,164
2003	133	1,073	10	469	237	0	5	0	2	37	4	292	2,262
2004	138	1,117	10	491	252	0	5	0	2	38	4	302	2,360
2005	144	1,161	10	514	266	0	5	0	2	39	4	312	2,458
2006	149	1,206	11	537	282	0	6	0	2	40	4	322	2,558
2007	154	1,248	11	560	287	0	6	0	2	41	4	331	2,645
2008	160	1,292	11	584	298	0	6	0	3	42	5	340	2,740
2009	165	1,337	11	609	307	0	6	0	3	43	5	350	2,835
2010	171	1,382	12	634	316	0	6	0	3	44	5	359	2,931
2011	176	1,426	12	659	322	0	7	0	3	45	5	368	3,023
2012	182	1,473	12	685	336	0	7	0	3	46	5	378	3,126
2013	188	1,519	12	712	341	0	7	0	3	46	5	388	3,221
2014	194	1,566	13	740	351	0	7	0	3	47	5	398	3,322
2015	200	1,614	13	768	357	0	7	0	3	48	5	408	3,422
2016	205	1,662	13	796	368	0	8	0	3	49	5	418	3,527
2017	212	1,713	13	826	375	0	8	0	3	50	5	428	3,634
2018	218	1,762	14	855	385	0	8	0	3	51	5	438	3,738
2019	224	1,810	14	884	391	0	8	0	3	52	5	448	3,839
2020	230	1,860	14	914	399	0	8	0	3	53	5	459	3,945
2021	236	1,910	14	946	405	0	9	0	3	54	5	469	4,050

A.2.3 System Peak Demand by Month

Monthly demand forecasts are not a requirement of RUS and have not been included in past Long-Range Load Forecasts by GRE. However, monthly data has been collected and econometric models are currently being developed to include this information in future forecasts. Until the models and analysis are complete we submit an estimate of monthly demand based on an eleven-year trend of our base case scenario (Scenario 1). This monthly forecast was not developed for the 2002 LRLF. It was specifically done for this Certificate of Need Application and therefore includes actual demand data through 2004 and will not correspond precisely to other data presented in this application.

Table A-4 – System Peak Demand by Month

Historical Demand (MW)												
	January	Feburary	March	April	May	June	July	August	September	October	November	December
1992	1,190	1,156	1,095	1,003	999	1,074	1,109	1,253	1,067	1,157	1,244	1,271
1993	1,255	1,268	1,199	1,046	925	1,156	1,229	1,360	1,032	1,156	1,242	1,312
1994	1,395	1,352	1,190	1,067	1,036	1,416	1,232	1,356	1,321	1,228	1,266	1,333
1995	1,355	1,299	1,229	1,118	1,044	1,508	1,553	1,525	1,339	1,214	1,388	1,455
1996	1,404	1,423	1,327	1,174	1,052	1,557	1,488	1,579	1,517	1,368	1,414	1,483
1997	1,456	1,329	1,268	1,182	1,093	1,585	1,610	1,501	1,409	1,327	1,367	1,403
1998	1,503	1,359	1,348	1,207	1,485	1,533	1,748	1,651	1,545	1,319	1,397	1,569
1999	1,590	1,440	1,376	1,228	1,247	1,674	1,875	1,735	1,725	1,380	1,479	1,602
2000	1,570	1,487	1,341	1,243	1,427	1,777	1,854	1,840	1,536	1,376	1,525	1,681
2001	1,617	1,572	1,452	1,275	1,575	1,955	2,033	2,094	1,603	1,549	1,637	1,698
2002	1,717	1,605	1,599	1,473	1,649	2,109	2,164	1,906	1,999	1,643	1,670	1,807
2003	1,859	1,798	1,705	1,500	1,388	1,894	2,148	2,306	1,960	1,605	1,750	1,873
2004	1,907	1,837	1,611	1,408	1,438	1,996	2,310	1,975	1,984	1,670	1,783	2,043
Forecast Demand (MW)												
	January	Feburary	March	April	May	June	July	August	September	October	November	December
2005	1,899	1,802	1,685	1,497	1,642	2,113	2,410	2,235	2,044	1,700	1,812	2,005
2006	1,952	1,853	1,732	1,536	1,697	2,177	2,509	2,313	2,113	1,746	1,861	2,067
2007	2,005	1,903	1,779	1,575	1,752	2,241	2,607	2,391	2,182	1,792	1,911	2,130
2008	2,059	1,954	1,826	1,615	1,807	2,305	2,705	2,468	2,251	1,838	1,960	2,192
2009	2,112	2,004	1,872	1,654	1,863	2,369	2,803	2,546	2,320	1,884	2,009	2,255
2010	2,165	2,055	1,919	1,693	1,918	2,434	2,902	2,624	2,389	1,930	2,059	2,317
2011	2,219	2,105	1,966	1,733	1,973	2,498	3,000	2,701	2,458	1,976	2,108	2,379
2012	2,272	2,156	2,013	1,772	2,028	2,562	3,098	2,779	2,527	2,022	2,158	2,442
2013	2,325	2,206	2,060	1,812	2,083	2,626	3,197	2,857	2,596	2,068	2,207	2,504
2014	2,379	2,257	2,107	1,851	2,138	2,690	3,295	2,934	2,665	2,114	2,256	2,567
2015	2,432	2,307	2,154	1,890	2,193	2,755	3,393	3,012	2,734	2,160	2,306	2,629
2016	2,485	2,358	2,201	1,930	2,248	2,819	3,491	3,090	2,803	2,206	2,355	2,691
2017	2,539	2,408	2,248	1,969	2,303	2,883	3,590	3,168	2,872	2,252	2,405	2,754
2018	2,592	2,459	2,295	2,008	2,358	2,947	3,688	3,245	2,941	2,299	2,454	2,816
2019	2,646	2,509	2,341	2,048	2,413	3,012	3,786	3,323	3,010	2,345	2,503	2,879
2020	2,699	2,560	2,388	2,087	2,468	3,076	3,885	3,401	3,079	2,391	2,553	2,941
2021	2,752	2,610	2,435	2,126	2,524	3,140	3,983	3,478	3,148	2,437	2,602	3,003

A.2.4 Annual Revenue per MWh

Table A-5 shows GRE's annual revenue per MWh for the forecast period.

Table A-5 – Annual Revenue Requirement per MWh

[TRADE SECRET INFORMATION BEGINS

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A.2.5 Average System Weekday Load Factor by Month

Weekday load factor by month is not available. The following average monthly load factor estimate is based on three years of monthly historical energy and demand data[4].

[4] This data includes the values for the city of Shakopee. GRE's responsibility for serving this load ends in 2006. Therefore, the Shakopee data has been removed from most of the data reporting in this application. The Shakopee

Table A-6 – Average Monthly Load Factor

Average Monthly Load Factor	
January	77%
Feburary	77%
March	77%
April	77%
May	74%
June	62%
July	66%
August	66%
September	62%
October	75%
November	76%
December	76%

A.3 Forecast Methodology

A.3.1 Overview

GRE and consulting staff prepared a large number of models, forecasts, tables and graphs to assist member system staff in developing their forecasts. GRE staff led the member system staff through a formal, systematic study process to derive information from the models and ensure that all critical factors affecting the forecast were examined. Each model was examined to determine if the historical data and necessary assumptions were reasonable for that member system. Member system staff then used information to develop their forecasts.

Using the models developed by GRE and consulting staff, each member system forecasted the number of consumers and the average energy usage per consumer, factoring in line losses, for each RUS classification of consumers. The member systems then summed the forecasted energy consumption for customer classes to achieve an annual system energy forecast. The final step in their forecasting was to use forecasted summer and winter load factors to correlate the annual energy forecast to their summer and winter system demand.

load has a similar load shape to that of GRE's load in the area and is not large compared to GRE's total. Thus the inclusion of this load does not significantly impact the calculation.

The GRE forecast is the sum of the member system forecasts plus GRE usage and transmission losses. There is one minor adjustment explained in the Large Commercial section.

This year, as a final check on the forecasting process, GRE also contracted with a consultant to complete an econometric forecast for GRE's system as a whole. As described later in this section, this econometric model produced a forecast that was very similar to the internal GRE forecast built up from the individual member system forecasts.

A.3.2 Customer Classes

During 2001, GRE served 540,003 members. The table below shows a breakdown of the number of consumers served and the percent of the overall energy sales attributed to each RUS class.

Table A-7 – 2001 Sales to Ultimate Consumers

[TRADE SECRET INFORMATION BEGINS

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A.3.3 Residential Models

Residential consumers represent a large percentage of GRE's energy sales and peak demand. It is important to note that the RUS Residential Consumer classification includes numerous types of accounts (e.g., homes and farms, crop dryers, farms, churches). Thus, residential consumer counts differ from the number of households. Because residential customers comprise the majority of GRE's demand and energy sales, GRE has historically focused considerable effort on the forecasting of the number of residential consumers and energy sales.

The method GRE uses for forecasting the number of residential consumers is a framework that assists member system staff in identifying, examining, and quantifying the factors that affect residential consumer growth. This methodology allows the incorporation of member system knowledge with the information in long-term demographic studies and econometric models. Each member system first used the GRE econometric models and demographic data to forecast number of residential consumers. Next, each member system used one of the models for forecasting usage per residential consumer. The final

forecast for this category was calculated by multiplying usage by forecasted consumers.

A.3.3.1 Number of Residential Consumers

GRE staff prepared five forecasts and demographic data for each member system. Each of these forecasts and data input provides useful information in aiding the member systems to forecast residential consumers. GRE staff also prepared graphs and tables to help compare these forecasts. Theses models and data, and their relative contributions to the forecast, are described below.

Seven-Year Linear Regression

GRE created a linear regression based on the historical number of customers for each member system using data from 1995 to 2001 and forecasted future years based on this data.

GRE then studied the graphs of residuals from linear trend models. Residuals are the difference between actual data and a straight line fit to the data. Each large residual was identified and explained. Large errors in the beginning and ending years could significantly skew the forecast. Certain other patterns in the residuals indicate non-linear growth. Residuals that are random and small indicate that linear regression fits the data well. If these conditions are met, this model provides a basis to be used in additional studies to assess whether growth will be higher or lower than the historical trend.

Eleven-Year Linear Regression

GRE also created a linear regression based on the historical number of customers for each member system using data from 1991 to 2001 and forecasted future years based on this data.

The eleven-year regression was analyzed like the seven-year regression described above. GRE also compared the two to see if the forecasts are consistent. Differences indicate changing conditions over time or possibly a one-time event distorting one of the forecasts. GRE helped member systems identify reasons for differences.

Percent of County Served Trend

GRE derived a linear trend using historical share of each county served and projected into the future. Then, these shares of counties served were multiplied by the Woods and Poole county household forecasts to achieve yearly forecasts of the number of consumers. Member system staff studied GRE prepared graphs of the changing percent of county served for each county in their service territory. They identified areas of current and potential

growth. Based on their knowledge of residential development plans, the member systems examined trend shares and assessed whether the trends would continue.

Woods and Poole Weighted County

A percentage of the households served (by the member systems) in each county for each member system was determined using 2001 data. These percentages were then multiplied by the Woods and Poole forecast household data for each year in each county to forecast the number of residential consumers. This is only a forecast of what will happen if consumers grow at the same rate as county households. In most member systems, consumers have not been growing a the same rate as county households, so GRE staff cautioned member system staff to use this only as a single data point among many for reference in determining their overall residential forecast.

Linear Relationship between Consumers and Woods and Poole Weighted County Data

A percentage of the households served in each county for each member system was determined using 2001 data. Those percentages were multiplied by the historical county data to develop a series that represents what the number of consumers would have been if the member system had always had the same share of county households. This variable is called the “constant weighted county” and is used as the independent variable in linear regression model with residential consumers as the dependant variable. This econometric model is calculated on an annual basis. The results of this model is compared with the results of the “trend share of percent of county served” model to distinguish the situation where the share of one county is growing rapidly but another county’s share is decreasing.

Demographic Data

GRE also studies demographic data such as the number of residential consumer added each year. This data is graphed and studied and the fluctuations in growth are related to factors such as recessions and interest rates. It is easy to quantify the effect of economic factors in most member systems. It is also clear that construction in some member systems is dominated by local patterns and shows no relationship with the national economy.

A.3.3.2 Residential Usage

GRE hosted a residential usage forecast team meeting for its member systems to ensure a structured review of factors affecting residential energy usage. The factors include heating and cooling degree-days, per capita income, competing

fuel prices, demand-side programs, conservation programs, air conditioning saturation, and historical and forecast electricity prices. GRE also discussed various appliance saturations and efficiencies with its member systems. GRE also discussed the models available for its members to forecast residential usage. Member system forecasters then completed a forecast, which was reviewed by their senior staff. GRE staff then visited the member systems to review and discuss each forecast.

Power System Engineering Econometric Model

Power Systems Engineering (PSE) developed an econometric model that represents residential use per consumer for a generic GRE member system. The model includes individual member system constants, heating degree-days, cooling degree-days, and real electric price (three-year moving average) for all members. The ratio of farms to residential consumers, real per capita income (in 2001 dollars), total employment in service industries, and total dairy cows are included for select members where these factors are believed to be important. Shift variables are also included for several cooperatives to account for large, unexplained variations in the historic usage trends.

The model was fit to historic annual data for the 1988 through 2001 period for the member systems providing a series with 406 observations. This sample of historic data tests model stability over a long period that includes some economic cycles. However, it does not extend back far enough to include events of remote significance to current usage patterns such as the oil crisis of the 1970s. A logarithmic model is used to capture the non-linear relationship between economic, demographic, and weather variables and usage. This specification also provides elasticity coefficients that conveniently describe the percentage change in usage that is expected to accompany a one percent change in the given independent variable.

Seven-Year and Eleven-Year Linear Regressions

Although it is designed for an “average” GRE member, not every individual system will match the PSE model. Thus, GRE developed seven-year and eleven-year linear regressions for member systems to use in comparison to the PSE econometric forecast in making their final determination. The residuals from these models were examined to see if linear trends were appropriate. As discussed in the earlier section the residuals were also examined within the context of annual weather data and changing weather trends.

A.3.3.3 Comparison of Forecast Methodologies

Because the individual member systems used the analytical tools presented to them differently, GRE completed a comparison of the forecasts to ensure accuracy. Since the PSE econometric model is intended to represent an "average" GRE member system, the sum of the PSE econometric model for the member systems provides a good benchmark against which to measure. Although some of the member systems did not find the PSE model a good representation of their systems, the individual deviations would be expected to offset each other when aggregated into the GRE system forecast.

As Table A-8 shows, the forecasts are close in the early years, but the GRE forecast is increasingly higher in the later years of the forecast horizon. GRE examined the PSE models to determine the cause for this deviation and found that the PSE model emphasized farm usage (in particular, a dairy cow variable) too heavily and inappropriately underestimated energy usage in GRE's large, suburban members. For this reason, GRE determined that even with the modifications to the PSE model, GRE's internal forecast was a better representation of its system.

Table A-8 – Forecast Comparison of Residential Energy

[TRADE SECRET INFORMATION BEGINS

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A.3.4 Small C&I Models

As with residential consumers, each GRE member system develops forecasts for the small commercial and industrial sector by first forecasting the number of consumers in this category and then forecasting usage per consumer. The methodologies used in each step are described below.

A.3.4.1 Number of Consumers

GRE staff prepared several models for small C&I customers for each member system. These models and data, and their relative contributions to the forecast, are described below.

Seven-Year and Eleven-Year Regression Analysis

As with the residential class, GRE created a linear regression based on the historical number of customers for each member system using data from 1995 to 2001 and 1991 to 2001. This was used for analysis as described in A.3.2.1.

Residential-Consumer Based Econometric Model

GRE staff prepared an econometric model relating small commercial consumer growth to residential consumer growth. For many member systems there is a good relationship between the number of residential consumers and the number of small commercial consumers. As the residential population expands, small commercial businesses develop to serve the population. Member system staff studied the historical relationship between these forecast categories to determine whether it provided an appropriate model for their system.

A.3.4.2 Usage per Consumer

PSE Econometric Model

As with the residential usage per consumer model, PSE initially attempted to develop a pooled time-series cross-sectional econometric model for consumers across all GRE member systems. A number of different models and methods were investigated, but the results were not satisfactory. The small C&I class is much less homogeneous than the residential sales category. To apply a single causative model across all member systems is not practical. Thus, PSE determined that the best approach would be to develop individual member econometric forecasts.

Typically, the projection methods for the individual small C&I consumer models are based on regression against employment and income, with shift variables included for certain member systems. The choice of income and employment variables is based on the strong causative relationship between growth in commercial consumers and job counts and consumer spending. Selection of specific causative variables was based on historic model fit and forecast results.

Seven-Year and Eleven-Year Linear Trend

Although it is designed for an “average” GRE member system, not every individual member will match the PSE model. Thus, GRE developed seven-year and eleven-year linear regressions for members to use in comparison to the PSE forecast in making their final determination. The residuals from these

models were examined to see if linear trends were appropriate. As discussed in the earlier section, the residuals were also examined within the context of annual weather data and changing weather trends.

Comparison of Forecasts

Because the individual member systems used the analytical tools presented to them differently, GRE completed a comparison of the forecasts to ensure accuracy. Since the PSE econometric model is intended to represent an "average" GRE member system, the sum of the PSE econometric model for the member systems provides a good benchmark to measure against. Although some of the member systems did not find the PSE model to be a good representation of their systems, the individual deviations would be expected to offset each other when aggregated into the GRE system forecast.

As Table A-9 shows, the forecasts are close in the early years, but the GRE forecast is increasingly higher in the later years of the forecast horizon. As explained in section A.3.2, GRE found that the PSE model placed too much emphasis on farm usage. Because of the strong correlation between residential and small commercial usage, this mischaracterization of GRE's system also resulted in an inappropriate underestimation of small C&I usage. For this reason, GRE determined that even with the modifications to the PSE model, GRE's internal forecast was a better representation of its system.

Table A-9 – Forecast Comparison of Small C&I Energy

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

A.3.5 Large C&I Models

Each GRE member system forecasts the number of consumers and the average energy usage of large commercial consumers based on existing individual consumers' operations and plans. The addition of a new consumer or large-scale upgrades to existing operations often require additional construction or an upgrade of electric distribution facilities to meet capacity requirements. Therefore, member systems are usually notified well in advance of any plans for new construction. Short-tem forecasting tends to be quite accurate.

However, beyond the short-term, the individual member systems are reluctant to forecast additional large C&I customers that are not currently in development. Consequently, GRE adjusts the member forecast of large commercial consumers to represent the likely addition of new large consumers to the overall GRE system. (For example, with 28 member systems, if each member system estimated a 25 percent chance of acquiring a large commercial consumer, GRE would add seven consumers.) Although the likelihood of acquiring each individual new large customer is small enough not to include in the forecast, the overall likelihood (across GRE's entire system) of acquiring some new large consumers is significant enough to include in the GRE forecast.

The GRE adjustment ensures that the future consumer growth does not fall below the growth in the in the initial years. This method is used because the member systems forecasts for the first five years are accurate, based on known construction plans and the amount of growth is expected to remain steady over time.

A.3.6 Other Forecasting Category Models

The remaining categories of GRE's forecast are: seasonal, irrigation, public street and highway, public authorities, and sales for resale. Together these five categories represent 5.2 percent of GRE's energy sales. Theses categories are all forecasted using historical trends and local knowledge of factors that would impact number of customers, usage and load factor.

A.3.7 Aggregate System Econometric Forecast

A.3.7.1 Introduction

In addition to its member-by-member forecast, Great River Energy contracted with independent consultant James D. Campbell to perform an aggregate econometric forecast for the entire GRE system. Mr. Campbell was selected because of his excellent reputation and his many years experience preparing econometric forecasts as the chief forecaster for Northern States Power Company.

This econometric forecast was prepared in 2002 using historical data through 2001. This study is an aggregate forecast of GRE's winter and summer

demand and energy. It does not provide forecasts by account type or by member system.

A.3.7.2 Summary Results

The following table shows the forecasts resulting from the contracted econometric system-wide forecast.

Table A-10 – Aggregate System Econometric Forecast Results

[TRADE SECRET INFORMATION BEGINS

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Mr. Campbell's econometric forecast compares favorably with the member-by-member forecasts performed by GRE and its member systems that were discussed in sections A.3.3 – A.3.6. In the year 2010, the econometric forecast is 0.5 percent higher for summer demand, 0.3 percent lower for winter demand, and 2.5 percent higher for system energy.

Mr. Campbell prepared three regional models to forecast the number of residential consumers. The GRE system was divided into the core metro cooperatives, the outer metro cooperatives, and the non-metro cooperatives. The then used the Woods and Poole forecasts of population by county to forecast the number of residential consumers in each of the three GRE regions.

The number of residential consumers was then used as an input in the models to forecast energy, winter demand, and summer demand.

The energy model used residential consumers, real household earnings per employee, real residential electricity prices, and heating and cooling degree-days. The winter and summer demand models used monthly indicators, temperatures, and the real residential price of electricity, number of residential customers, and real earnings per household.

A.3.7.3 Conclusions

The econometric forecast developed by Mr. Campbell serves to confirm the results of GRE's in-house member-by-member forecast. This is not surprising, as the individual system forecasts are derived using many of the same econometric indicators that were used by Mr. Campbell in conducting the aggregate forecast. Mr. Campbell's forecast also confirms that GRE's future demand and energy growth is largely dependent on the growth of residential consumers in its service territory. Accurately forecasting the growth in residential consumers is a key factor in deriving an accurate forecast for GRE.

A.3.8 Computations and Variables Used in Analysis

The complete set of computations, variables, and results used in GRE's forecast is considered trade secret and would be too voluminous to present in this application. This data is available for review at GRE's offices during regular business hours, upon prior arrangement. GRE includes in this application a sampling of the variables used in its analysis.

The following variables were used in the PSE models:

Table A-11 – Variables used in the PSE Models

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

The following variables were used in the independently contracted GRE system forecast:

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

A.3.9 Databases Used in the Forecast

The RUS Form 7 is the source of historical member system data on the number of consumers by each RUS class, their kWh usage, and the revenue collected. The RUS classes are: residential, residential seasonal, irrigation, small commercial (1000Kva or less), large commercial (greater than 1000 Kva), public street and highway lighting, public authorities, and sales for

resale. The average of each month's data is reported for the residential, small commercial and public authorities number of consumers. The peak number of consumers for the year is reported in the other categories.

Periodically, "Residential Surveys" are done to determine consumers per county, type of residential consumers, size of residence, people per residence, age of house, appliance ownership and age, and consumer age. These surveys are used as the source for historical appliance data, as documented in the Long-Range Load Forecast.

GRE used several sources for its demographic information. Woods and Poole is the source of historical and forecast data for county households, county employment, and income. The Woods and Poole county data was weighted to reflect the proportion of consumers in each county. The member systems often serve small proportions of large counties. Unless the data is weighted, the data from these counties exert undue influence. The Metropolitan Council demographic data for county households was used for member systems located close to the metropolitan area. Since demographic information is only available by county, GRE used a weighting factor to convert the county data into data by individual member system.

Weather data was obtained from the Midwest Regional Climate Center.

Federal Home Mortgage Association provided a forecast of mortgage interest rates.

A.3.10 Analysis of Forecast Methodology

A.3.10.1 Overview

GRE's forecast methodology is a robust process that utilizes statistical and econometric forecasting models as well as the local knowledge that our member systems are uniquely positioned to provide. GRE constantly strives to examine and improve its processes and feedback from regulatory proceedings is one input that GRE considers in making improvements. In GRE's 2003 IRP, the Minnesota Public Utilities Commission (MPUC) ordered GRE in future forecasts to respond to the Department of Commerce's (Department)

concerns regarding the documentation of adjustments to the econometric forecasts and having the DSM implicitly embedded in the forecast.

GRE is implementing process improvements as a result of the IRP proceeding. These process improvements are being included in GRE's 2004 load forecast process. As explained in Section 2, RUS rules require GRE to use an RUS-approved forecast for all planning purposes. Thus, GRE is using the RUS approved 2002 load forecast data, which does not include the improvements, in this application. However, GRE is confident in the validity of the 2002 load forecast. As explained in depth in its 2003 IRP and also summarized in this appendix, GRE contracted for an independent, system-wide econometric forecast in addition to its internally generated forecast. The results of the independent forecast verified GRE's forecast.

In response to the Department's prior concerns, GRE is improving its documentation. For example, GRE is documenting the specific instances in which specific local knowledge regarding development or other economic factors results in an improvement to the forecast over the strict use of modeling results. Also as a result of the 2003 IRP proceedings, GRE contracted for an extensive analysis of the treatment of DSM in its forecast. This began with an assessment of available data and estimation of the historical impact of DSM on GRE's demand. Next, the analysis will examine how to best incorporate the impacts of DSM in future forecasts. GRE will report the results of this effort in its next IRP, scheduled to be filed on or before July 1, 2005.

A.3.10.2 Strengths and Weaknesses

The 2002 LRLF forecasting cycle provided GRE a unique opportunity to examine the strengths and weaknesses of its forecasting process. Since GRE also contracted for an independent system-wide econometric forecast, it could compare the two techniques and results.

The comparison is essentially between a singly-developed GRE system forecast and a sum of individually-developed member forecast. GRE's "bottom up" approach is the most appropriate to use because it meets GRE's many forecasting needs, including: RUS forecasting requirements, usefulness for both transmission and resource planning, and appropriate involvement of GRE's member co-ops.

GRE is required by RUS to coordinate member system forecasting efforts and to use the resulting forecast in all planning efforts. In practice this means

using the sum of the individual member system forecasts for planning purposes. GRE also needs regional forecasts by member system to plan the transmission system.

Another critical element of the GRE forecast is the appropriate involvement of its member systems. The GRE forecast process is designed to tap into the critical local service-area knowledge of its member cooperatives. The GRE member systems must also understand and approve the GRE forecast. The present forecasting process develops this understanding and acceptance for the member systems.

Outside observers have suggested that this involvement of member systems is a weakness to the GRE forecast because of the data requirements involved and the ad hoc changes that are made to the modeling results. GRE disagrees. When changed to modeling results reflect superior knowledge of the relevant variables, GRE considers these changes to be improvements. Although the data requirements to support forecasts for several customer classes for each of 28 member systems is at times challenging, the reward in the usefulness of the individual forecasts justifies the process.

It would be cost prohibitive to pursue multiple forecasts for each forecasting cycle. GRE contracted for the independent forecast to use as a one-time analytical tool. As mentioned earlier, the results of the contracted forecast and GRE's internal forecast were closely correlated. Thus there were no significant gains from the additional forecast to justify the ongoing expense.

A.3.10.3 Past Accuracy

As explained in Section 2, GRE provided forecast information in this application based on its 2002 load forecast. Thus, GRE is in a position to compare actual data to the first three years of this forecast. Table A-12 below shows the comparison of summer peaks examining scenarios 1 and 5 from the 2002 load forecast and actual data.

Table A-12 - Comparison of Summer Peaks: 2002 Load Forecast to Actual

Year	Scenario 1 Forecast	Scenario 5 Forecast	Actual
2002	2089	2164	2164
2003	2162	2261	2306
2004	2333	2358	2377

The 2002 LRLF Scenario 1 forecast was too low because residential consumer growth was higher than anticipated. When the 2002 Long-Range Load Forecast was completed it was assumed that interest rates would increase and housing starts would decrease. Instead interest rates stayed low and record construction of new homes resulted. Scenario 5 came much closer to capture the higher demand, as it is designed to do. Scenario 5 was accurate for 2002, about 2 percent below actual for 2003 and less than one percent below actual for 2004. This demonstrates the prudency of using Scenario 5 for planning purposes.

Table A-13 below shows the comparison of the base case winter forecast versus actual.

Table A-13 – Comparison of the Base Case Forecast: Winter Forecast versus Actual

Year	Base Case Forecast	Actual
2002-2003	1861	1859
2003-2004	1916	1907

Actual winter demand for those two seasons was less than one percent less than that which is forecasted. The base case is a reasonable representation of GRE's winter peak. Since the winter peak is less than the summer peak, it is not the primary driver of capacity planning and is adequately covered as a result of capacity obtained to meet peak summer needs.

A.3.11 Assumptions and Special Information

This section responds to the requirement in Minn. Rules 7849.0270 subp. 5. GRE's assumptions included:

- Alternate forms of energy will be available and competitively prices.
- No significant switching to electricity from other fuels will occur, because other fuels will remain available and competitively priced.
- Future prices of electricity were explicitly modeled within the forecast.
- The effects of energy conservation were assumed to continue in the future as they had in the past.

A.3.12 Coordination of Forecasts with Other Systems

The forecast of GRE was not coordinated with any other system.

APPENDIX B SYSTEM CAPACITY

B.1 Introduction

This appendix provides the information required by Minnesota Rules pt. 7849.0280, System Capacity. The load forecast included in the below referenced load and capability tables reflects the final version of the 2002 Long Range Load Forecast and any all-requirements load obligations for customers other than members of GRE.

B.2 Power Planning Program (MAPP 15% minimum reserve requirement)

GRE is a member of MAPP with load responsibility. This means GRE is responsible for maintaining the 15 percent minimum capacity reserve margin that MAPP requires as part of its reserve sharing pool for MAPP members. The reserve sharing pool concept is a key reason why MAPP was formed. By sharing reserves in a pool, individual members can carry lower reserves than if they were not members of the pool. The 15 percent minimum capacity reserve margin is expected to maintain adequate reliability based on historical experience.

The 15 percent minimum capacity reserve margin means that if a MAPP member has, for example, an annual peak load of 100 MW, the member must maintain accredited capacity of 115 MW to meet the minimum reserve requirement.

The 15 percent minimum capacity reserve margin is characterized as "planning capacity reserves" yet each member of MAPP with load responsibility must not just *plan* to meet the reserve margin, they also must maintain the 15 percent minimum capacity reserve margin on an actual basis. At the time a MAPP member's annual peak load occurs, the member must have a 15 percent minimum capacity reserve margin. Failure to do so results in a substantial penalty in the form of a required MAPP capacity purchase "after the fact". The current price for after the fact capacity is $45,000 per MW minimum and $90,000 per MW maximum in each season a member fails to maintain the minimum reserve margin. The price varies in proportion to the size of the capacity deficit relative to the member's load: a bigger deficit results in a higher price.

A key concept in MAPP is accreditation of capacity both for owned-generation resources and transaction resources. Only resources that have been accredited by MAPP can be part of the reserve sharing pool and used in the calculation of planning reserves. The reserve sharing pool attempts to take into account the effect of planned and forced equipment outages by requiring the 15 percent minimum capacity planning reserves. As long as the planned and forced outages experienced are not significantly different than those experienced historically, these outages are not a factor affecting reliability.

Given the uncertainty in any load forecast, MAPP members typically plan to have reserves in excess of 15 percent of the expected peak load forecast. The uncertainty in a very short-term (one year or less) load forecast is largely driven by weather sensitivity. GRE's weather sensitivity has increased significantly over the last 15 years, reflecting the tremendous increase in air conditioner saturations and usage over that time period. GRE has conducted evaluations of weather sensitivity to estimate the level of reserves needed to deal with this risk. These evaluations are done a few times each year to provide guidance on how much additional capacity to buy or sell to maintain a desired level of reserves in excess of the 15 percent minimum capacity reserves. GRE makes its long-term generation planning decisions to meet the 15 percent minimum capacity reserve margin MAPP requires, based on the long-term demand forecast produced in the Long Range Load Forecast. As explained in Section 2 of this Application, GRE uses a demand forecast with an estimated 10% chance of being exceeded for long-term capacity planning purposes. In the short term, GRE evaluates the impact of weather sensitivity and adjusts its reserve margin to reflect the expected short-term peak load forecast.

B.3 Load and Capability for Forecast Period

The information required by Minnesota Rules pt. 7849.0280, System Capacity, B-F, is presented here in the form of several load and capability tables. These tables contain the following information:

- Table B-1: load and capability information with existing resources for the historic portion of the forecast period (1993-2004), summer season
- Table B-2: load and capability information with existing resources for the historic portion of the forecast period(1993-2004), winter season
- Table B-3: load and capability information with existing resources for the future portion of the forecast period (2005-2020), summer season

- Table B-4: load and capability information with existing resources for the future portion of the forecast period (2005-2020), winter season
- Table B-5: This table is a restated version of Table B-3.

Together, Tables B-1 through B-5 fulfill the requirements of Rule 7849.0280, subparts B, C, and D. Tables B-1 through B-4 are completed in the format of MAPP load and capability tables, which account for firm and participation purchases and sales as well as the other items listed in part D. Table B-5 is a restructured version of Table B-3 in a format that illustrates overall capacity in a more straightforward manner than the MAPP load and capability tables. GRE created this table for the summer season only, as it is summer demand that drives the need for the proposed project.

- Table B-6: load and capability information with the Project for the future portion of the forecast period (2005-2020), summer season
- No table is required for the winter season of the future portion of the forecast. GRE does not need additional winter capacity at this time and the proposed project is not expected to be accredited for the winter season.

Tables B-6 fulfills the requirements of Rule 7849.0280, subparts E and F. Subpart F asks for all projected purchases, sales, and generating capability in addition to that related to the proposed facility. For GRE, this is the existing resources with the addition of the Project, as explained further in section B.4 of this Appendix.

Table B-1 – GRE System Load and Capability – Summer (history)

GRE Peak Load	1359	1416	1568	1612	1647	1784	1920	1908	2166	2230	2376	2377

GRE SYSTEM LOAD & CAPABILITY

NEEDS: SUMMER (History)	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**
Updated: 01-10-2005	***1993***	***1994***	***1995***	***1996***	***1997***	***1998***	***1999***	***2000***	***2001***	***2002***	***2003***	***2004***
1 MONTHLY SYSTEM DEMAND PLUS CID ACTUALLY SERVED (2+3)	1359	1416	1568	1612	1647	1784	1920	1908	2166	2230	2376	2377
2 SCHEDULE L PURCHASED THAT HOUR	0	0	0	0	0	0	0	0	0	0	0	0
3 MONTHLY SYSTEM DEMAND	1359	1416	1568	1612	1647	1784	1920	1908	2166	2230	2376	2377
4 ANNUAL DEMAND	1395	1416	1568	1612	1647	1784	1920	1908	2166	2230	2376	2377
5 FIRM POWER PURCHASES	298	322	472	497	563	549	679	489	369	315	320	260
6 FIRM POWER SALES	4	4	28	38	65	25	0	30	75	75	75	75
7 ADJ MONTHLY DEMAND (3-5+6)	1065	1098	1124	1153	1149	1261	1242	1450	1873	1990	2131	2192
8 ADJ ANNUAL DEMAND (4-5+6)	1101	1098	1124	1153	1149	1261	1242	1450	1873	1990	2131	2192
9 NET GENERATION CAPACITY	1446	1446	1446	1446	1446	1446	1426	1446	2210	2332	2404	2398
10 PART POWER PURCHASES	197	197	198	198	209	295	275	493	240	332	312	302
11 PART POWER SALES	194	173	243	188	194	221	197	168	281	315	172	82
12 ADJ NET CAPABILITY (9+10-11)	1449	1470	1401	1456	1461	1520	1504	1771	2169	2349	2544	2618
13 NET RESERVE OBLIGATION (8*15%)	165	165	169	173	172	189	186	217	281	299	320	329
14 FIRM CAPACITY OBLIGATION (7+13)	1230	1263	1293	1326	1321	1450	1428	1667	2153	2289	2451	2521
15 CAPACITY SURPLUS/DEFICIT (12-14)	***218***	***207***	***108***	***130***	***140***	***70***	***76***	***104***	***15***	***60***	***93***	***97***
16 EFFECTIVE RESERVE (%)	***33%***	***31%***	***23%***	***25%***	***26%***	***20%***	***20%***	***21%***	***16%***	***18%***	***19%***	***19%***
FIRM PURCHASES												
WAPA (UPA)	5	4	3	3	3	4	4	4	4	4	4	4
MH DivEx	0	0	150	150	150	150	150	150	150	150	150	150
ENRON	0	0	0	75	130	200	200	200	0	0	0	0
BEPC	0	25	70	70	70	25	25	25	35	35	0	0
HUC	0	0	0	0	0	20	20	20	20	20	20	0
NSP	50	50	0	0	0	0	100	0	0	0	0	0
WAPA (CP)	99	109	89	89	90	90	90	90	85	86	86	86
MP	0	0	35	0	10	0	30	0	50	0	40	0
HCPD	9	9	0	0	0	0	0	0	0	0	0	0
IPW	75	75	75	75	60	0	0	0	0	0	0	0
IIGE	60	50	50	0	0	0	0	0	0	0	0	0
MH	0	0	0	35	50	0	0	0	0	0	0	0
MPC	0	0	0	0	0	50	50	0	0	0	0	0
OPPD	0	0	0	0	0	10	10	0	0	0	0	0
SRE	0	0	0	0	0	0	0	0	25	0	0	0
CMMPA	0	0	0	0	0	0	0	0	0	18	18	18
BEPC	0	0	0	0	0	0	0	0	0	1	1	1
MMPA	0	0	0	0	0	0	0	0	0	2	2	2
Total FIRM PURCHASES	***298***	***322***	***472***	***497***	***563***	***549***	***679***	***489***	***369***	***315***	***320***	***260***
FIRM SALES												
AMPA	4	4	0	0	0	0	0	0	0	0	0	0
WLMR	0	0	0	0	23	0	0	0	0	0	0	0
MMPA	0	0	28	38	42	25	0	30	0	0	0	0
NSP (Koch)	0	0	0	0	0	0	0	0	75	75	75	75
Total FIRM SALES	***4***	***4***	***28***	***38***	***65***	***25***	***0***	***30***	***75***	***75***	***75***	***75***
PART POWER PURCHASES												
ELKR	10	10	10	10	6	10	10	10	10	10	10	10
MOLK	4	4	4	4	4	4	4	4	4	4	4	4
DPC	0	0	0	0	15	0	0	0	0	0	0	0
CMMPA	0	0	0	0	0	44	20	20	0	0	0	0
DPC (Genoa #3)	183	183	184	184	184	187	184	172	172	171	169	170
ESI (Stoneman)	0	0	0	0	0	50	28	26	26	25	0	0
GSE Netting Agreement	0	0	0	0	0	0	13	11	10	9	11	
OPPD	0	0	0	0	0	0	16	0	0	0	0	0
AEMC	0	0	0	0	0	0	0	50	0	0	0	0
AEP	0	0	0	0	0	0	0	150	0	0	0	0
WR	0	0	0	0	0	0	0	50	0	0	0	0
EA (Lake Marion and Hastings)	0	0	0	0	0	0	0	0	18	18	18	18
MHEB	0	0	0	0	0	0	0	0	0	50	50	50
RREC	0	0	0	0	0	0	0	0	0	45	50	0
MEC	0	0	0	0	0	0	0	0	0	0	0	50
Total PART POWER PURCHASES	***197***	***197***	***198***	***198***	***209***	***295***	***275***	***493***	***240***	***332***	***312***	***302***
PART POWER SALES												
NSP DivEx	0	0	50	50	50	50	50	50	50	50	50	50
Willmar	12	13	13	13	14	16	17	18	20	22	24	26
MMPA	0	0	20	25	30	30	30	0	0	0	0	0
HUC	10	10	10	0	0	0	0	0	0	0	0	0
NSP	22	0	0	0	0	0	0	0	0	0	0	0
WPL	50	50	50	0	0	25	0	0	0	0	0	0
IPW	100	100	100	100	100	100	100	100	0	0	0	0
MP	0	0	0	0	0	0	0	0	211	243	88	0
OTP	0	0	0	0	0	0	0	0	0	0	10	0
GSE Netting Agreement	0	0	0	0	0	0	0	0	0	0	0	6
Total PART POWER SALES	***194***	***173***	***243***	***188***	***194***	***221***	***197***	***168***	***281***	***315***	***172***	***82***

Table B-2 - GRE System Load and Capability – Winter (history)

GRE Peak Load	1395	1364	1487	1483	1528	1622	1645	1721	1738	1853	1918	2102
GRE SYSTEM LOAD & CAPABILITY												
NEEDS: WINTER (History)	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**UPA + CP System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**	**GRE System Totals**
Updated: 01-10-2005	***1993***	***1994***	***1995***	***1996***	***1997***	***1998***	***1999***	***2000***	***2001***	***2002***	***2003***	***2004***
1 MONTHLY SYSTEM DEMAND PLUS CID ACTUALLY SERVED (2+3)	1395	1364	1487	1483	1528	1622	1645	1721	1738	1853	1918	2102
2 SCHEDULE L PURCHASED THAT HOUR	0	0	0	0	0	0	0	0	0	0	0	0
3 MONTHLY SYSTEM DEMAND	1395	1364	1487	1483	1528	1622	1645	1721	1738	1853	1918	2102
4 ANNUAL DEMAND	1395	1416	1363	1612	1647	1920	1784	1908	2166	2230	2376	2376
5 FIRM POWER PURCHASES	165	197	272	352	371	427	347	222	163	124	164	164
6 FIRM POWER SALES	6	0	150	150	150	191	150	225	225	230	225	225
7 ADJ MONTHLY DEMAND (3-5+6)	1236	1167	1365	1281	1307	1386	1448	1724	1800	1960	1980	2164
8 ADJ ANNUAL DEMAND (4-5+6)	1236	1219	1241	1410	1426	1684	1587	1911	2228	2337	2438	2438
9 NET GENERATION CAPACITY	1446	1446	1446	1446	1446	1447	1447	1443	2287	2472	2495	2499
10 PART POWER PURCHASES	197	194	303	244	251	273	332	601	296	345	314	314
11 PART POWER SALES	95	73	93	39	71	71	47	18	292	296	124	127
12 ADJ NET CAPABILITY (9+10-11)	1548	1567	1656	1651	1626	1649	1732	2026	2291	2521	2685	2686
13 NET RESERVE OBLIGATION (8*15%)	185	183	186	212	214	253	238	287	334	350	366	366
14 FIRM CAPACITY OBLIGATION (7+13)	1421	1350	1551	1493	1521	1639	1686	2011	2134	2310	2345	2529
15 CAPACITY SURPLUS/DEFICIT (12-14)	***126***	***217***	***105***	***159***	***105***	***10***	***46***	***15***	***156***	***211***	***339***	***156***
16 EFFECTIVE RESERVE (%)	***24%***	***31%***	***22%***	***26%***	***22%***	***16%***	***18%***	***16%***	***22%***	***24%***	***29%***	***21%***
FIRM PURCHASES												
WAPA (Kandi)	5	6	6	6	6	6	6	6	6	6	6	6
BEPC	0	40	40	85	45	45	45	45	45	0	0	0
HUC	0	0	0	20	20	20	20	20	0	0	0	0
MP	0	0	25	0	0	125	125	0	0	0	40	40
WAPA (CP)	110	101	101	101	110	101	101	101	97	97	97	97
NSP	50	50	100	25	75	0	0	0	0	0	0	0
MHEB	0	0	0	50	0	0	0	0	0	0	0	0
WPPI	0	0	0	15	15	0	0	0	0	0	0	0
MPC	0	0	0	50	50	50	50	50	0	0	0	0
SONAT	0	0	0	0	50	0	0	0	0	0	0	0
GSE to UPA	0	0	0	0	0	80	0	0	0	0	0	0
CMMPA	0	0	0	0	0	0	0	0	15	18	18	18
BEPC	0	0	0	0	0	0	0	0	0	1	1	1
MMPA	0	0	0	0	0	0	0	0	0	2	2	2
Total FIRM PURCHASES	***165***	***197***	***272***	***352***	***371***	***427***	***347***	***222***	***163***	***124***	***164***	***164***
FIRM SALES												
MHEB DivEx	0	0	150	150	150	150	150	150	150	150	150	150
AMPA	6	0	0	0	0	0	0	0	0	0	0	0
CP to UPA (via GSE)	0	0	0	0	0	41	0	0	0	0	0	0
NSP (Koch)	0	0	0	0	0	0	0	75	75	75	75	75
WLMR	0	0	0	0	0	0	0	0	0	5	0	0
Total FIRM SALES	***6***	***0***	***150***	***150***	***150***	***191***	***150***	***225***	***225***	***230***	***225***	***225***
PART POWER PURCHASES												
ELKR	10	10	10	6	10	10	10	10	10	10	10	10
MOLK	4	4	4	4	4	4	4	4	4	4	4	4
DPC (Genoa #3)	183	180	184	184	187	181	184	181	183	181	182	182
NSP DivEx	0	0	50	50	50	50	50	50	50	50	50	50
MHEB	0	0	55	0	0	0	50	0	0	0	0	0
ESI (Stoneman)	0	0	0	0	0	28	25	26	25	28	0	0
GSE Netting Agreement	0	0	0	0	0	0	9	7	6	5	0	0
EA (Lake Marion and Hastings)	0	0	0	0	0	0	0	18	18	18	18	18
SRE	0	0	0	0	0	0	0	100	0	0	0	0
MP	0	0	0	0	0	0	0	205	0	0	0	0
MHEB	0	0	0	0	0	0	0	0	0	50	50	50
Total PART POWER PURCHASES	***197***	***194***	***303***	***244***	***251***	***273***	***332***	***601***	***296***	***345***	***314***	***314***
PART POWER SALES												
WPL	50	50	50	0	25	25	0	0	0	0	0	0
WLMR	13	13	13	14	16	16	17	18	20	22	24	26
HUC	10	10	10	0	0	0	0	0	0	0	0	0
NSP	22	0	0	0	0	0	0	0	0	0	0	0
IPW	0	0	0	0	0	0	0	0	0	0	0	0
MMPA	0	0	20	25	30	30	30	0	0	0	0	0
MP	0	0	0	0	0	0	0	0	272	274	100	100
GSE Netting Agreement	0	0	0	0	0	0	0	0	0	0	0	1
Total PART POWER SALES	***95***	***73***	***93***	***39***	***71***	***71***	***47***	***18***	***292***	***296***	***124***	***127***

Table B-3 – GRE System Load and Capability – Summer Forecasted Demand

FORECASTED DEMAND (2002 LRLF)	2533.0	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
GRE SYSTEM LOAD & CAPABILITY																
NEEDS:	**GRE and**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**
DATE: 01-11-2005	**Shakopee**															
	Summer 2005	***Summer 2006***	***Summer 2007***	***Summer 2008***	***Summer 2009***	***Summer 2010***	***Summer 2011***	***Summer 2012***	***Summer 2013***	***Summer 2014***	***Summer 2015***	***Summer 2016***	***Summer 2017***	***Summer 2018***	***Summer 2019***	***Summer 2020***
1 MONTHLY SYSTEM DEMAND PLUS CID SERVED (2+3)	2533.0	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
2 SCHEDULE L PURCHASED AT PEAK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 MONTHLY SYSTEM DEMAND	2533.0	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
4 ANNUAL SYSTEM DEMAND	2533.0	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
5 SEASONAL FIRM PURCHASES	435.3	430.8	415.8	414.8	414.8	239.8	239.8	239.8	239.8	239.8	89.8	89.8	89.8	89.8	89.8	89.8
6 SEASONAL FIRM SALES	116.0	126.0	126.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 MONTHLY ADJUSTED DEMAND (3-5+6)	2213.7	2253.4	2354.7	2406.6	2501.1	2771.9	2782.7	2886.7	2981.2	3082.4	3332.3	3437.6	3544.3	3648.2	3749.5	3854.8
8 ANNUAL ADJUSTED DEMAND (4-5+6)	2213.7	2253.4	2354.7	2406.6	2501.1	2771.9	2782.7	2886.7	2981.2	3082.4	3332.3	3437.6	3544.3	3648.2	3749.5	3854.8
9 NET GENERATION CAPACITY	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6
10 PART POWER PURCHASES	344.2	355.7	305.7	203.9	203.9	203.9	203.9	203.9	203.9	203.9	203.9	186.3	186.3	186.3	186.3	186.3
11 PART POWER SALES	132.0	134.0	130.0	80.0	80.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
12 ADJ NET CAPABILITY (9+10-11)	2602.8	2612.3	2566.3	2514.5	2514.5	2564.5	2564.5	2564.5	2564.5	2564.5	2564.5	2576.9	2576.9	2576.9	2576.9	2576.9
13 NET RESERVE OBLIGATION (8*15%)	332.1	338.0	353.2	361.0	375.2	415.8	417.4	433.0	447.2	462.4	499.8	515.6	531.6	547.2	562.4	578.2
14 FIRM CAPACITY OBLIGATION (7+13)	2545.8	2591.4	2707.9	2767.6	2876.3	3187.7	3200.1	3319.7	3428.4	3544.8	3832.1	3953.2	4075.9	4195.4	4311.9	4433.0
15 CAPACITY SURPLUS/DEFICIT (12-14)	***57.0***	***20.9***	***-141.6***	***-253.1***	***-361.8***	***-623.2***	***-635.6***	***-755.2***	***-863.9***	***-980.3***	***-1267.6***	***-1376.3***	***-1499.0***	***-1618.5***	***-1735.0***	***-1856.1***
16 EFFECTIVE RESERVE (%)	***17.6%***	***15.9%***	***9.0%***	***4.5%***	***0.5%***	***-7.5%***	***-7.8%***	***-11.2%***	***-14.0%***	***-16.8%***	***-23.0%***	***-25.0%***	***-27.3%***	***-29.4%***	***-31.3%***	***-33.2%***
FIRM PURCHASES																
WAPA (Kandiyohi)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MHEB Diversity Exchange	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0
WAPA (CP)	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5
CMMPA (Wright-Hennepin)	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Dakota Electric)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Minnesota Valley)	5.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Stearns)	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MMPA (Steele Waseca)	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BEPC (Wright-Hennepin)	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	130.0	130.0	130.0	130.0	130.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	45.0	45.0	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM PURCHASES	***435.3***	***430.8***	***415.8***	***414.8***	***414.8***	***239.8***	***239.8***	***239.8***	***239.8***	***239.8***	***89.8***	***89.8***	***89.8***	***89.8***	***89.8***	***89.8***
FIRM SALES																
NSP (Koch)	81.0	81.0	81.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (SMMPA)	35.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM SALES	***116.0***	***126.0***	***126.0***	***81.0***	***81.0***	***81.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***
PART POWER PURCHASES																
ELKR	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
MOLK	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
GSE (Genoa #3)	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3
EA (Lake Marion and Hastings)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	0.0	0.0	0.0	0.0	0.0
MHEB	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP (EXCLUSIVES)	90.3	101.8	101.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER PURCHASES	***344.2***	***355.7***	***305.7***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***186.3***	***186.3***	***186.3***	***186.3***	***186.3***
PART POWER SALES																
NSP Diversity Exchange	50.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WLMR	28.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
GSE (Netting)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (GSE)	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER SALES	***132.0***	***134.0***	***130.0***	***80.0***	***80.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***

Table B-4 – GRE Load and System Capability – Winter Forecasted Demand

FORECASTED DEMAND (2002 LRLF)	2028.0	2076.0	2128.0	2179.0	2230.0	2278.0	2335.0	2386.0	2440.0	2492.0	2547.0	2599.0	2654.0	2706.0	2760.0	2810.0
GRE SYSTEM LOAD & CAPABILITY																
NEEDS:	**GRE and**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**
DATE: 01-11-2005	**Shakopee**															
	Winter 2005	***Winter 2006***	***Winter 2007***	***Winter 2008***	***Winter 2009***	***Winter 2010***	***Winter 2011***	***Winter 2012***	***Winter 2013***	***Winter 2014***	***Winter 2015***	***Winter 2016***	***Winter 2017***	***Winter 2018***	***Winter 2019***	***Winter 2020***
1 MONTHLY SYSTEM DEMAND PLUS CID SERVED (2+3)	2028.0	2076.0	2128.0	2179.0	2230.0	2278.0	2335.0	2386.0	2440.0	2492.0	2547.0	2599.0	2654.0	2706.0	2760.0	2810.0
2 SCHEDULE L PURCHASED AT PEAK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 MONTHLY SYSTEM DEMAND	2028.0	2076.0	2128.0	2179.0	2230.0	2278.0	2335.0	2386.0	2440.0	2492.0	2547.0	2599.0	2654.0	2706.0	2760.0	2810.0
4 ANNUAL SYSTEM DEMAND	2533.0	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
5 SEASONAL FIRM PURCHASES	306.1	297.6	286.6	286.6	285.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6
6 SEASONAL FIRM SALES	276.0	276.0	276.0	231.0	231.0	231.0	150.0	150.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0
7 MONTHLY ADJUSTED DEMAND (3-5+6)	1997.9	2054.4	2117.4	2123.4	2175.4	2398.4	2374.4	2425.4	2479.4	2531.4	2436.4	2488.4	2543.4	2595.4	2649.4	2699.4
8 ANNUAL ADJUSTED DEMAND (4-5+6)	2502.9	2536.6	2633.9	2684.8	2780.3	3051.1	3061.9	3165.9	3260.4	3361.6	3311.5	3416.8	3523.5	3627.4	3728.7	3834.0
9 NET GENERATION CAPACITY	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6
10 PART POWER PURCHASES	406.7	418.2	368.2	266.4	216.4	216.4	216.4	216.4	216.4	216.4	216.4	198.8	198.8	198.8	198.8	198.8
11 PART POWER SALES	181.0	181.0	180.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
12 ADJ NET CAPABILITY (9+10-11)	2730.3	2741.8	2692.8	2741.0	2691.0	2691.0	2691.0	2691.0	2691.0	2691.0	2691.0	2703.4	2703.4	2703.4	2703.4	2703.4
13 NET RESERVE OBLIGATION (8*15%)	375.4	380.5	395.1	402.7	417.0	457.7	459.3	474.9	489.1	504.2	496.7	512.5	528.5	544.1	559.3	575.1
14 FIRM CAPACITY OBLIGATION (7+13)	2373.3	2434.9	2512.5	2526.1	2592.4	2856.1	2833.7	2900.3	2968.5	3035.6	2933.1	3000.9	3071.9	3139.5	3208.7	3274.5
15 CAPACITY SURPLUS/DEFICIT (12-14)	***357.0***	***306.9***	***180.3***	***214.9***	***98.6***	***-165.1***	***-142.7***	***-209.3***	***-277.5***	***-344.6***	***-242.1***	***-297.5***	***-368.5***	***-436.1***	***-505.3***	***-571.1***
16 EFFECTIVE RESERVE (%)	***32.3%***	***29.5%***	***23.3%***	***24.8%***	***19.4%***	***8.4%***	***9.2%***	***6.7%***	***4.3%***	***1.9%***	***5.5%***	***3.6%***	***1.2%***	***-1.0%***	***-3.1%***	***-5.1%***
FIRM PURCHASES																
WAPA (Kandiyohi)	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
WAPA (CP)	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3
CMMPA (Wright-Hennepin)	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Dakota Electric)	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Minnesota Valley)	5.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Stearns)	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MMPA (Steele Waseca)	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BEPC (Wright-Hennepin)	1.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	130.0	130.0	130.0	130.0	130.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	45.0	45.0	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM PURCHASES	***306.1***	***297.6***	***286.6***	***286.6***	***285.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***
FIRM SALES																
MHEB Diversity Exchange	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0
NSP (Koch)	81.0	81.0	81.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (SMMPA)	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM SALES	***276.0***	***276.0***	***276.0***	***231.0***	***231.0***	***231.0***	***150.0***	***150.0***	***150.0***	***150.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***
PART POWER PURCHASES																
NSP Diversity Exchange	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ELKR	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
MOLK	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
GSE (Genoa #3)	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7
EA (Lake Marion and Hastings)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	0.0	0.0	0.0	0.0	0.0
MHEB	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP (EXCLUSIVES)	90.3	101.8	101.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER PURCHASES	***406.7***	***418.2***	***368.2***	***266.4***	***216.4***	***216.4***	***216.4***	***216.4***	***216.4***	***216.4***	***216.4***	***198.8***	***198.8***	***198.8***	***198.8***	***198.8***
PART POWER SALES																
GSE (Netting)	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WLMR	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
SRE (GSE)	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	100.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER SALES	***181.0***	***181.0***	***180.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***

Table B-5 – Simplified Summer GRE System Load and Capability

SIMPLIFIED SUMMER GRE SYSTEM LOAD & CAPABILITY

DATE: 01-11-2005	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PURCHASES (* 15% ADDED FOR FIRM PURCHASES)																
* WAPA (Kandiyohi)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
* MHEB Diversity Exchange	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	0.0	0.0	0.0	0.0	0.0	0.0
* WAPA (CP)	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5
* CMMPA (Wright-Hennepin)	6.9	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* CMMPA (Dakota Electric)	4.6	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* CMMPA (Minnesota Valley)	5.8	5.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* CMMPA (Stearns)	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* MMPA (Steele Waseca)	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* BEPC (Wright-Hennepin)	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* MP	149.5	149.5	149.5	149.5	149.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* MP	51.8	51.8	51.8	51.8	51.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ELKR	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
MOLK	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
GSE (Genoa #3)	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3
EA (Lake Marion and Hastings)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	0.0	0.0	0.0	0.0	0.0
MHEB	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP (EXCLUSIVES)	90.3	101.8	101.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PURCHASES (TOTAL)	**844.8**	**851.1**	**783.9**	**680.9**	**680.9**	**479.7**	**479.7**	**479.7**	**479.7**	**479.7**	**307.2**	**289.6**	**289.6**	**289.6**	**289.6**	**289.6**
SALES (* 15% ADDED FOR FIRM SALES)																
* NSP (Koch)	93.2	93.2	93.2	93.2	93.2	93.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* SRE (SMMPA)	40.3	51.8	51.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NSP Diversity Exchange	50.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WLMR	28.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
GSE (Netting)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (GSE)	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SALES (TOTAL)	**265.4**	**278.9**	**274.9**	**173.2**	**173.2**	**123.2**	**30.0**	**30.0**	**30.0**	**30.0**	**30.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
GENERATION (TOTAL)	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**
FORECASTED LOAD	2533.0	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
FORECASTED LOAD (PLUS 15% RESERVES)	**2913.0**	**2941.9**	**3041.2**	**3151.5**	**3260.1**	**3370.3**	**3475.9**	**3595.5**	**3704.2**	**3820.5**	**3935.4**	**4056.5**	**4179.2**	**4298.7**	**4415.2**	**4536.3**
SURPLUS/DEFICIT (GENERATION + PURCHASES - SALES - LOAD PLUS 15% RESERVES)	**57.0**	**20.9**	**-141.6**	**-253.1**	**-361.8**	**-623.2**	**-635.6**	**-755.2**	**-863.9**	**-980.3**	**-1267.6**	**-1376.3**	**-1499.0**	**-1618.5**	**-1735.0**	**-1856.1**

Table B-6 - GRE Load and System Capability – Summer Forecasted Demand with New Peaker

FORECASTED DEMAND (2002 LRLF)	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
GRE SYSTEM LOAD & CAPABILITY																
NEEDS:	**GRE and Shakopee**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**
DATE: 02-14-2005																
	Summer 2005	***Summer 2006***	***Summer 2007***	***Summer 2008***	***Summer 2009***	***Summer 2010***	***Summer 2011***	***Summer 2012***	***Summer 2013***	***Summer 2014***	***Summer 2015***	***Summer 2016***	***Summer 2017***	***Summer 2018***	***Summer 2019***	***Summer 2020***
1 MONTHLY SYSTEM DEMAND PLUS CID SERVED (2+3)	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
2 SCHEDULE L PURCHASED AT PEAK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 MONTHLY SYSTEM DEMAND	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
4 ANNUAL SYSTEM DEMAND	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
5 SEASONAL FIRM PURCHASES	435.3	430.8	414.8	414.8	414.8	239.8	239.8	239.8	239.8	239.8	89.8	89.8	89.8	89.8	89.8	89.8
6 SEASONAL FIRM SALES	116.0	126.0	126.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 MONTHLY ADJUSTED DEMAND (3-5+6)	2217.9	2253.4	2355.7	2406.6	2501.1	2771.9	2782.7	2886.7	2981.2	3082.4	3332.3	3437.6	3544.3	3648.2	3749.5	3854.8
8 ANNUAL ADJUSTED DEMAND (4-5+6)	2217.9	2253.4	2355.7	2406.6	2501.1	2771.9	2782.7	2886.7	2981.2	3082.4	3332.3	3437.6	3544.3	3648.2	3749.5	3854.8
9 NET GENERATION CAPACITY	2390.6	2390.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6	2560.6
10 PART POWER PURCHASES	344.2	355.6	305.7	203.9	203.9	203.9	203.9	203.9	203.9	203.9	203.9	186.3	186.3	186.3	186.3	186.3
11 PART POWER SALES	132.0	134.0	130.0	80.0	80.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
12 ADJ NET CAPABILITY (9+10-11)	2602.8	2612.2	2736.3	2684.5	2684.5	2734.5	2734.5	2734.5	2734.5	2734.5	2734.5	2746.9	2746.9	2746.9	2746.9	2746.9
13 NET RESERVE OBLIGATION (8*15%)	332.7	338.0	353.4	361.0	375.2	415.8	417.4	433.0	447.2	462.4	499.8	515.6	531.6	547.2	562.4	578.2
14 FIRM CAPACITY OBLIGATION (7+13)	2550.6	2591.4	2709.1	2767.6	2876.3	3187.7	3200.1	3319.7	3428.4	3544.8	3832.1	3953.2	4075.9	4195.4	4311.9	4433.0
15 CAPACITY SURPLUS/DEFICIT (12-14)	***52.2***	***20.8***	***27.2***	***-83.1***	***-191.8***	***-453.2***	***-465.6***	***-585.2***	***-693.9***	***-810.3***	***-1097.6***	***-1206.3***	***-1329.0***	***-1448.5***	***-1565.0***	***-1686.1***
16 EFFECTIVE RESERVE (%)	***17.4%***	***15.9%***	***16.2%***	***11.5%***	***7.3%***	***-1.3%***	***-1.7%***	***-5.3%***	***-8.3%***	***-11.3%***	***-17.9%***	***-20.1%***	***-22.5%***	***-24.7%***	***-26.7%***	***-28.7%***
FIRM PURCHASES																
WAPA (Kandiyohi)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MHEB Diversity Exchange	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0
WAPA (CP)	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5
CMMPA (Wright-Hennepin)	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Dakota Electric)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Minnesota Valley)	5.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Stearns)	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MMPA (Steele Waseca)	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BEPC (Wright-Hennepin)	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	130.0	130.0	130.0	130.0	130.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	45.0	45.0	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM PURCHASES	***435.3***	***430.8***	***414.8***	***414.8***	***414.8***	***239.8***	***239.8***	***239.8***	***239.8***	***239.8***	***89.8***	***89.8***	***89.8***	***89.8***	***89.8***	***89.8***
FIRM SALES																
NSP (Koch)	81.0	81.0	81.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (SMMPA)	35.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM SALES	***116.0***	***126.0***	***126.0***	***81.0***	***81.0***	***81.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***
PART POWER PURCHASES																
ELKR	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
MOLK	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
GSE (Genoa #3)	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3
EA (Lake Marion and Hastings)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	0.0	0.0	0.0	0.0	0.0
MHEB	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP (EXCLUSIVES)	90.3	101.7	101.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER PURCHASES	***344.2***	***355.6***	***305.7***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***186.3***	***186.3***	***186.3***	***186.3***	***186.3***
PART POWER SALES																
NSP Diversity Exchange	50.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WLMR	28.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
GSE (Netting)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (GSE)	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER SALES	***132.0***	***134.0***	***130.0***	***80.0***	***80.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***

B.4 Proposed Generation Retirements and Additions

Table B-7 – Proposed Generation Retirements and Additions (Minn. Rule Pt. 7849.0280 (G))

	Retirements	Additions		
Year	MW	MW	Unit Type	CON Application Date
2005	0	0		
2006	0	0		
2007	0	170	Combustion Turbine	Feb-05
2008	0	0		
2009	0	0		
2010	0	0		
2011	0	0		
2012	0	0		
2013	0	0		
2014	0	0		
2015	0	0		
2016	0	0		
2017	0	0		
2018	0	0		
2019	0	0		

GRE has no planned retirements during the forecast period.

GRE is currently considering projects in addition to the one proposed in this filing, which if pursued would require certificates of need. However, none are far enough under development to be included in this list. These other anticipated projects include additional peaking generation in 2009 and higher capacity factor generation in the range of 2011 – 2014. GRE is also analyzing proposals to participate in additional generation proposed by other parties in the region. Modeling results in the upcoming IRP will help determine which projects we proceed with.

GRE has used a Request for Proposals (RFP) process to assure any resource additions selected meet the test of being cost effective by including other market participants. In 2003 GRE issued an RFP for renewable resources that resulted in the selection of a 100 MW (nameplate) wind project. The wind project (Trimont) is currently under construction and is expected to be in commercial operation by the 4th quarter of 2005. This project, along with GRE's other renewable resources, fulfills the Renewable Energy Objective's

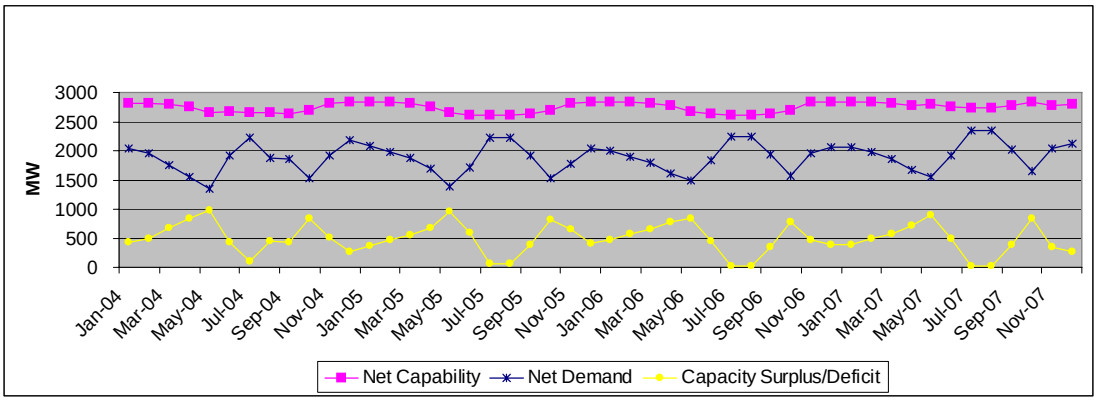
guidelines for GRE through 2007. GRE will likely explore additional wind resources to be online after that time.

GRE issued an RFP for peaking resources in 2004. Given the excess of simple cycle generating equipment that existed at the time, we expected to receive a large number of competitive offers. We did receive a large number of responses but ultimately none were competitive on price. A self-build alternative by GRE was ultimately the preferred option as GRE could also take advantage of the lower equipment prices, as well as relatively low-cost financing capabilities.

B.5 Monthly Adjusted Net Demand and Net Capability

In response to Minnesota Rules pt. 7849,0280 subp. H., the following table shows the monthly adjusted net demand and net capability for 2004 – 2007. A separate table factoring in maintenance is not necessary. Generation capacity with an outage of less than one year remains accredited. This is one of the generation reserve sharing pool's design characteristics and is covered by adjusting the planning reserve margin level. Therefore, net demand and capability is unaffected by the regularly scheduled maintenance outages that GRE will experience during the time horizon.

Figure B-1 – Monthly Adjusted Net Demand and Net Capability for 2004 - 2007



B.6 Discussion of System Reserve Margins

Minnesota Rules pt. 7849.0280, Subp. I, System Capacity, requires a discussion of the appropriateness and method of determining reserve margin levels considering:

- Forced outages of generating units
- Deviation from load forecasts
- Scheduled maintenance of generation and transmission facilities
- Power exchange impact on reserve requirements
- Transfer capabilities

The 15 percent minimum reserve level required by MAPP along with the additional capacity GRE maintains, as described above, is intended to cover the historical patterns of forced outages and scheduled maintenance of generation and transmission facilities in the MAPP region. As long as the historical patterns of forced and scheduled outages continue, this minimum reserve level appears to be sufficient yet not overly conservative. New generation is expected to be added and old generation retired which should continue a similar pattern of forced and scheduled outages.

The reserve margin is also expected to cover the deviation from forecast for an individual MAPP member. With GRE experiencing continued load sensitivity based on weather conditions, the need to have an adequate reserve will continue.

Changes in the power and energy market are likely to change short-term power exchanges in the region. The emergence of the Midwest ISO as the regional authority governing GRE has not changed the existing reserve requirements. Module E of MISO's tariff is the interim resource adequacy policy and primarily serves to supplement existing rules, in particular for any utility not subject to existing requirements, such as the MAPP reserve requirement. MISO plans to propose a new resource adequacy policy approximately one year after market start. Stakeholders are currently providing input, but nothing specific has yet been developed. GRE participates in the relevant stakeholder forums and will closely monitor any proposed changes to the policies.

There is continuing pressure to use the transmission system at the most efficient level possible. The regional transmission system was built for two primary purposes: serving native load and emergency ties to other regions. It is now being used for bulk power transfers between regions on a regular basis.

Additional generation will help increase reliability if it is sited appropriately to the transmission grid that can best use the new generation.

APPENDIX C CONSERVATION PROGRAMS

C.1 Introduction

This appendix fulfills the Minnesota Rules 7840.0290 requirements for the Minnesota Certificate of Need information relating to conservation and load management programs. The following pages describe Great River Energy's Demand-Side Management (DSM) programs, which includes load management and conservation. Only the programs that reduce summer peak demand were quantified because they have direct impact on the need for the project.

Load management programs utilize an infrastructure of communication and control systems to remotely turn loads off during peak periods. Restoring load management programs requires consideration of the load shape to avoid secondary or rebound peaks. Energy conservation programs reduce energy usage over all hours of operation. These programs also reduce the peak load if they are on during the peak period.

Prior to 1999, Cooperative Power Association (CP) and United Power Association (UPA) had successfully implemented DSM since the late 1970s. Great River Energy used many CP and UPA programs as a starting point, established many new programs. GRE continues to work with the member distribution cooperatives to develop additional programs. Gary Connett, Manager of Member and Resource Services, is responsible for Great River Energy's DSM programs.

C.2 Great River Energy DSM Goals

Great River Energy considers DSM programs as important resource options in its planning process. In Great River Energy's 2004 Conservation Improvement Program filing with the Minnesota Department of Commerce (2004 CIP filing) the following goals were established by the member cooperatives for energy and demand savings.

Figures C-1 and C-2 show the recent history of demand and energy savings as well as the forecasted levels included in the 2004 CIP filing.

Figure C-1 - Energy Savings

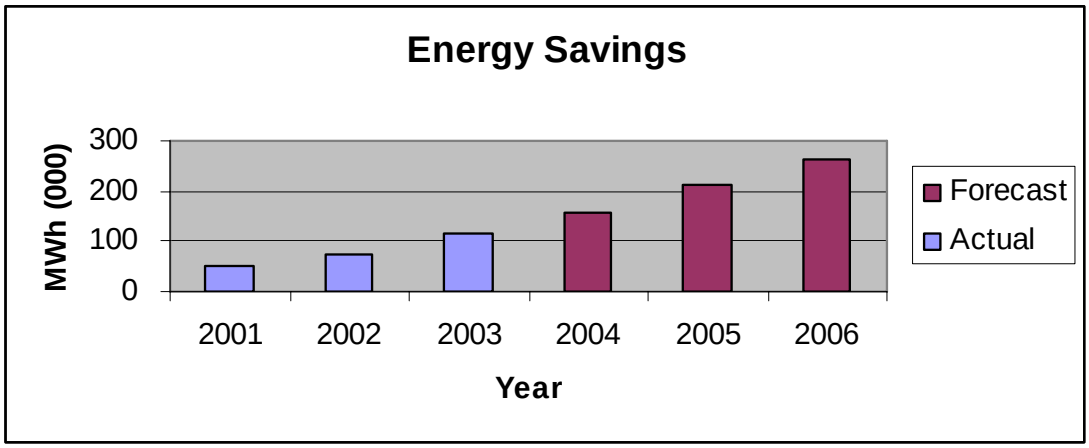
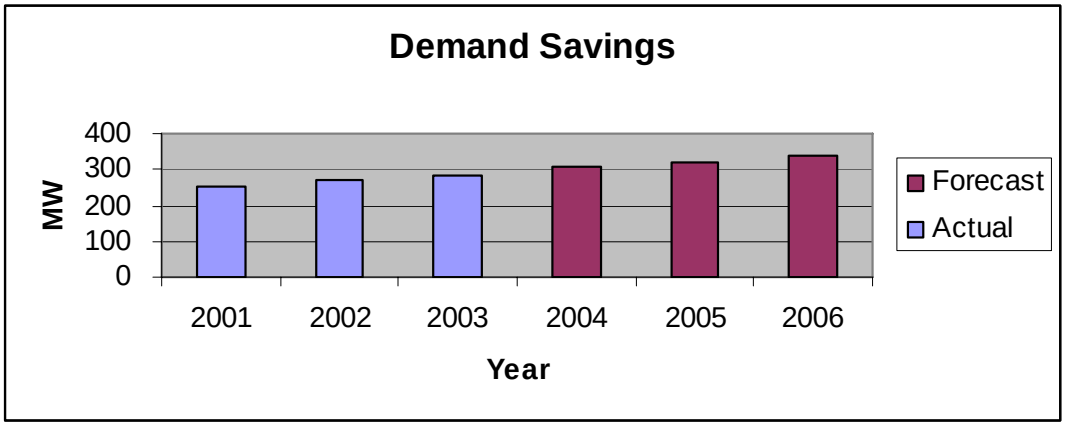


Figure C-2 - Demand Savings



Great River Energy's DSM programs were able to reduce the 2003 summer peak by more than 300 MW (approximately 12 percent of peak). The programs are expected to reduce the summer peak from 2004 to 2007 by an additional 56 MW for a total reduction of 401 MW. Despite continued growth of load management and conservation programs, these programs will be unable to provide enough capacity to delay or avoid constructing the proposed project. Factors limiting the feasibility of supplying this deficit with load management and conservation include: a limited enrollment of new customers, increased drop out rate of current customers and the potential for secondary or rebound peaks during load restoration that are higher than the original peaks.

In 2003, Great River Energy retained Global Energy Partners, an EPRI affiliated company, to conduct an assessment of its (DSM) efforts and to assist in the development of new, cost-effective DSM programs. The assessment provided Great River Energy with a useful estimate of the overall potential for energy and capacity savings from various DSM programs. This study prompted a shift in focus to programs that provided more summer demand reduction capability – particularly programs that impact high efficiency residential air conditioning. This resulted in Great River Energy significantly increasing its budget for residential air conditioning rebates. Great River Energy expects to rebate approximately 5,500 high efficiency residential air conditioners in 2005. Great River Energy's goals are to continue to enhance and expand existing programs that meet customers' needs while providing the organization with an opportunity to economically reduce summer peak demands.

C.3 Existing Load Management and Energy Conservation Programs

Through CP and UPA, Great River Energy has a long history of implementing load management and conservation programs. Both cooperatives had been implementing programs since the late 1970s. From this start, Great River Energy has effectively built over 30 load control and conservation programs that are equivalent to a 345 MW peaking power plant. The power plant equivalent value is calculated using the 2004 estimate of the load control and conservation programs (300 MW) and the 15 percent MAPP reserve requirements. The following tables summarize the kW reduction and the Great River Energy programs that have the greatest impact on summer peak demand:

Table C-1 GRE DSM Summer Peak kW Reduction Program Totals Including Distribution and AC Losses

	Peak Water Heaters	Storage Water Heaters	Cycled Air	High Efficiency Air	Ground Source Heat Pump	Irrigation	C&I Interruptible	C&I Conservation Rebates	Mine/Other	Total
2002	20,484	31,025	94,888	1,038	415	49,473	96,670	2,039	6,880	302,911
2003	21,041	32,254	100,669	1,086	422	52,762	107,000	6,942	6,892	329,068
2004	21,770	32,856	104,590	1,316	428	54,372	115,917	7,200	6,900	345,349
2005	22,399	33,953	109,935	1,650	434	54,947	124,031	7,450	6,905	361,704
2006	23,046	35,087	115,552	1,727	441	57,051	132,713	8,834	6,906	381,359
2007	23,712	36,259	121,457	1,808	447	59,237	142,003	9,630	6,904	401,457

Table C-2 Great River Energy Summer Peak Reduction Participants

	Peak Water Heaters	Storage Water Heaters	Cycled Air	High Efficiency Air	Ground Source Heat Pump	Irrigation	C&I Interruptible	C&I Conservation Rebates	Mine/Other	Total
2002	34,140	51,708	94,888	3,459	1,384	2,151	889	292	83	188,994
2003	35,068	53,757	100,669	3,621	1,407	2,294	984	367	85	198,252
2004	36,283	54,760	104,590	4,388	1,426	2,364	1,066	434	87	205,398
2005	37,332	56,589	109,935	5,500	1,447	2,389	1,141	475	89	214,896
2006	38,410	58,479	115,552	5,758	1,469	2,480	1,220	518	91	223,978
2007	39,521	60,432	121,457	6,027	1,491	2,576	1,306	564	93	233,467

These savings can be tied back to the specific impact on the forecast by examining which customer classes participate in the various programs. This participation is based on the retail distribution cooperatives' estimates and is as follows:

- Peak Water Heaters: Residential
- Storage Water Heaters: Residential
- Cycled Air: Residential
- High Efficiency Air Conditioner: Residential
- Ground Source Heat Pump: approximately 70% residential, 30% small commercial
- Irrigation: irrigation
- C&I Interruptible: approximately 80% small commercial, 20% large commercial
- C&I Conservation Rebates: approximately 20% small commercial, 80% large commercial
- Mine/Other: references GRE's ability to interrupt power to the coal mine serving Coal Creek Station

The primary purposes of Great River Energy's diverse portfolio of DSM programs are to reduce peak demand, encourage energy conservation and improve energy efficiency. The programs allow Great River Energy to efficiently utilize existing generation resources. Descriptions of the programs are provided under the following categories:

- energy conservation programs
- direct load control programs

C.3.1 Great River Energy's Energy Conservation Programs

Energy Audits: Great River Energy and its member systems offer free or reduced cost energy audits for customers. Many member systems have staff trained to conduct basic audits.

Commercial: Commercial consumers are initially provided with either a walk-through energy audit provided by cooperative staff or a more comprehensive audit performed by a professional consultant. Costs for the comprehensive audit are shared 35 percent by Great River Energy, 35 percent by the distribution cooperative and 30 percent by the customer.

Residential: Home Energy Check is a residential energy efficiency program that includes in-home energy audits and conservation workshops for consumers. Beyond educating consumers on how to make their homes more energy-efficient, this program offers other assistance including low-interest financing. Outside auditors are hired to do more complex studies. This program has been expanded to include implementation of measures prescribed by the audit.

Commercial Energy Efficiency Programs:

The Commercial and Industrial Energy Grant and Rebate Program: This program solicits proposals from farm and business owners for energy and peak demand reduction projects. The proposals are evaluated for viability and cost-effectiveness. Selected projects are awarded grants or rebates. Great River Energy funds these projects through a fixed annual budget that determines the number of projects that can be approved. Projects receiving funding may include lighting retrofits, motor replacement, adjustable speed drive installations, air conditioning replacement and refrigeration efficiency improvements. In 2003, the program helped reduce the summer peak by 6,942 kW and saved an estimated 26,170 MWh.

Residential Energy Efficiency Programs:

High Pressure Sodium Lighting: Great River Energy member cooperatives offer incentives to replace outdoor mercury vapor security lights with high-pressure sodium units. The program is typically implemented when residential

customers replace a 175-watt mercury vapor light with a 100-watt sodium unit.

Residential Lighting: In 2003 and 2004 Great River Energy participated in the *Change a Light, Change the World* residential lighting program, which promoted the sale of fluorescent light bulbs. Great River Energy, its member cooperatives and other Minnesota utilities were recognized by the national Environmental Protection Agency (EPA) for outstanding participation in this ENERGY STAR promotion.

Residential ENERGY STAR® Appliance Rebate Program: As a result of the Global Energy Partners DSM assessment, Great River Energy instituted an ENERGY STAR Residential Appliance Rebate Program in 2003 for clothes washers, dishwashers and refrigerators. Since the program's inception over 10,773 appliances have been rebated. This has resulted in a demand savings of 646 kW and an energy savings of approximately 1,301 MWh. GRE anticipates 5,400 rebates to be issued in 2005.

Residential ENERGY STAR Air Conditioner Rebate Program: As a result of the Global Energy Partners DSM Assessment, Great River Energy instituted an ENERGY STAR Residential Air Conditioning Rebate Program in 2003. The program rebates ENERGY STAR rated central and room air conditioners. Since the program's inception, Great River Energy has rebated 11,468 central air conditioners. This has resulted in a demand savings of 3,440 kW and an energy savings of 5,947.6 MWh. Great River Energy anticipates 5,500 rebates to be issued in 2005.

C.3.2 Great River Energy Direct Load Control Programs

Great River Energy offers a variety of direct load control programs that allow the organization to substantially reduce its summer and winter peak demand. These programs include the following:

Water Heating Programs:

Electric Thermal Storage (ETS) Water Heating. An ETS water heating system has sufficient storage capacity to supply hot water needs over an extended on-peak period when the electrical supply is interrupted. ETS water heaters are

interrupted for 16 hours daily. Recharge is limited to eight hours generally from 11 p.m. until 7 a.m.

Peak Shave Water Heating. A peak shave water heating system is one which has sufficient storage capacity to supply hot water needs while the electric supply is interrupted over a limited on-peak period. Great River Energy peak shave water heaters are interrupted for four to six hours on days of high electrical demand and during system emergencies.

Cycled Air Conditioning:

Great River Energy offers a cycled air conditioning program that cycles the residential air conditioner compressor on for 15 minutes and off for 15 minutes during summer season peak periods. The temperature in the home increases during the cycled air conditioning control period. Great River Energy limits the control periods to six hours, which has helped reduce the number of dissatisfied customers and program fallout.

Currently, nearly 100,000 residential customers participate in Great River Energy's cycled air conditioning program. Several distribution cooperatives have more than 50 percent of the central air conditioners in their service territory under control. In the future, the summer daily peak load shape is expected be flatter and may require more hours of load control to avoid secondary or rebound peaks. Extended hours of control will lead to larger temperature increases in the homes and potentially more consumer discomfort. Surveys indicate that some consumers would leave the program if they become too uncomfortable during load control periods.

Heat Pumps:

Great River Energy and its member cooperatives offer an air-source heat pump program that targets customers who plan to install central air conditioning. Air-source heat pumps are generally more efficient and use less energy than standard central air conditioners. Air-source heat pumps also provide customers with the added benefit of home heating during spring and fall at efficiencies that are up to three times greater than the most efficient fossil-fuel systems.

Add-on Heat Pumps. In the heating mode, the air-source heat pump is thermostatically controlled to shut off when the outside temperature is less than 25 degrees Fahrenheit. At that point, a non-electric system supplies the home heating needs. The spring and fall electric heating load does not contribute to the summer peak or winter peak, so no additional generating capacity is required.

Ground-source Heat Pumps. Ground-source heat pumps (GSHP) offer consumers the most efficient heating and cooling system available today. Because heat energy is absorbed from the earth, GSHPs also have efficiencies up to three times greater than the most efficient fossil-fuel system. GSHPs also offer cooling at higher efficiencies than standard central air conditioners.

GSHPs are stand-alone systems capable of providing whole-house space conditioning. They are sized for heating and may also include water heating capability. In the cooling mode, the GSHP functions as a central air conditioner. In the heating mode, the GSHP provides the homes total heating needs down to design conditions.

Controlled Irrigation:

Irrigation loads are under the cooperative member systems' time-of-day rates and are controlled by Great River Energy to reduce summer peaks. Controlled irrigation systems are interrupted for up to four hours per day during summer season peak periods.

Controlled C/I Loads:

Generator Assistance Program. The Generator Assistance Program (GAP) provides a rate incentive to commercial customers who have isolated on-site generation to run when requested by Great River Energy. The generator is either automatically started by Great River Energy or the customer. Generator operation does not exceed 10 hours in any 24-hour period, and annual run time is limited to 300 hours. The Generator Assistance Program makes use of existing generators that many consumers require for reliability and also provides an incentive for other customers to consider installing new generation.

Electric Thermal Storage Space Heating:

Electric Thermal Storage Space Heating (ETS) can provide whole-house space heating by storing heat produced from electricity during an eight hour off-peak period. A number of different media can be used to store heat during the off-peak periods; the most common are ceramic brick, water and sand. The three commercially available storage heating configurations are central, room or dispersed, and concrete slab.

Central Storage. A central off-peak electric storage furnace consists of a storage medium and controls which sense charge requirements for the eight-hour off-peak period. The charge controller senses the outdoor night-time temperature to determine how much heat will be required the following day. Electric elements within the storage core heat bricks or water to a predetermined temperature to provide the heating for the entire 16-hour on-peak period.

Room Storage. A room storage system supplies the room's heating needs from individual storage heaters. Each occupied room in the home has one or more storage heaters. These units operate in the same manner as a central off-peak storage furnace. When the room thermostat calls for heat, the fan comes on and moves air through the heater core and into the room. The mixture of static discharge and fan-forced convection allows for precise temperature control.

Slab Storage Heating. This type of storage heating utilizes the concrete slab and sand beneath it as a radiant heat source. This medium provides a heat reservoir for storing heat produced by electrical cables or mats buried in the sand under the concrete floor. This insulated heat reservoir supplies radiant heat to the home all day and is charged during the eight-hour off-peak period.

Dual Fuel Heating:

Dual fuel systems are combination electric and non-electric heating systems. A conventional electric furnace is the primary heating system and oil, gas, LP or wood fuel the secondary or backup system. Although a wood backup system is allowed, it is discouraged because it is not automatic. The secondary system must be capable of heating the entire home for an extended period of time. Operation of the secondary system is limited to no more than 400 hours per heating season.

C.4 Future Load Management and Conservation Plans

By providing the appropriate incentives to the customer, Great River Energy projects additional growth in the number of participants for load management and conservation programs. Other cost-effective programs that provide value to the customer and accomplish Great River Energy's objectives will be considered for implementation, particularly programs that reduce summer peaks. However, the impact of load control programs on the peak will be monitored closely to avoid secondary or rebound peaks.

Great River Energy also will consider how its participation in the Midwest Independent System Operator (Midwest ISO) will impact future load management and conservation programs. These programs will likely play an important role in the Midwest ISO market and will continue to provide cost savings to Great River Energy and the consumer. Great River Energy will need to identify and resolve load management issues in this new environment.

Great River Energy continues to review its current DSM programs and evaluate potential new programs on the basis of cost effectiveness and customer satisfaction. In the short term, programs that reduce summer peaks will continue to be the most beneficial. However, in the long term, as Great River Energy considers other generation resources, programs that reduce energy throughout the day will become equally important. The following is an example of programs that may be considered for further marketing efforts:

- commercial energy audit program
- commercial heat pump program
- residential heat pump program

Commercial Energy Audit Program:

The objectives of the energy audit program would be to promote energy efficiency and to help identify customer energy needs. Many Great River Energy members already provide these audits for consumers. Separate audits would be developed for the following customer groups:

- agricultural
- small commercial

- large commercial

The audits would be educational in nature and help identify energy savings opportunities for the customer and provide the member cooperative with information regarding the customer's energy usage and needs. The audit could also be used as a vehicle to promote other energy conservation programs sponsored by the member cooperatives.

Commercial Heat Pump Program:

The objective of the commercial heat pump program would be to encourage the use of efficient electric heating and cooling technologies. Many of Great River Energy's northern member cooperatives have implemented this program. The program could provide an additional benefit to customers because they would not be subject to direct load control.

Because heat pumps are generally more expensive to install than conventional equipment, Great River Energy and the member cooperatives may need to offset the cost of the equipment through a rebate. The member cooperatives would be responsible for administration and promotion of this program. Great River Energy would be responsible for program design and planning as well as the evaluation of program costs.

Residential Heat Pump Program:

The objective of the residential heat pump program would be to encourage the use of efficient heat pumps for residential heating and cooling. The program could provide an additional benefit to customers because they would not be subject to direct load control. The following heat pump technologies would be promoted:

- air source heat pumps
- ground source heat pumps

The member cooperatives would be responsible for administration and promotion of the program. Great River Energy would be responsible for program design and planning as well as the evaluation of program costs.

C.5 Load Management and Conservation programs that have not been implemented

Great River Energy and the distribution cooperatives design and promote load management and conservation programs that provide financial incentives to the end users for managing electric loads and conserving energy. The distribution cooperatives have the flexibility to customize programs to meet their customers' needs. Great River Energy tries to design programs that are beneficial to all of its members. Great River Energy's board approves incentives for these programs. The distribution cooperatives ultimately decide which programs to implement and how to pass on the Great River Energy incentives.

Several programs have been considered but not implemented due to the low benefit-cost ratios or other market barriers. Some of the programs that have not been implemented include the following:

- residential
  - shading of central AC unit
  - multi-speed furnace fan rebate
- commercial
  - energy efficient cooking appliances
  - cool storage

C.6 Conservation Accomplishments

In addition to managing a cost-effective DSM program for nearly two decades, Great River Energy was instrumental in the development of the Conservation Improvement Program (CIP) cost/benefit worksheet that its member cooperatives and various municipal utilities use to complete their biennial CIP filing, which is submitted to the Minnesota Department of Commerce. Great River Energy is also a major participant in the design and construction of an energy efficient model home to be built in Elk River, Minnesota. Energy City is coordinating the construction of the energy efficient home. Energy City is a project of the Energy Alley program of the Minnesota Environmental Initiative. The home will be open to the public for two years and provide opportunities to educate the home building community

and the public about successful approaches to energy efficient home design and construction.

C.7 Cost of Conservation Programs

Great River Energy has made significant investments in load management and conservation programs. The 2005 load management and conservation programs budget for Great River Energy and its member systems totals more than $17 million; this represents more than 2 percent of the member cooperatives' gross operating revenue. The member system budgets account for the majority of this total. However, Great River Energy has increased its 2005 rebate budget by nearly 25 percent to over $3.7 million. This additional money will be used for energy efficient appliance and air conditioning rebates and C&I energy grants. Customers also bear a share of the program costs. Their costs tend to be for equipment and installation costs. Rate credits to the distribution cooperatives and consumers also help promote the programs.

Table C-3 lists GRE's budgeted spending per program for 2004. The spending for the storage water heating, interruptible irrigation, and the C&I interruptible program are expected to remain approximately the same in the future. These programs receive no rebates or grants from GRE and are promoted from the retail member system level. The cycled air conditioning, high efficiency air conditioning, and C&I energy rebate program receives funding from GRE. GRE has increased its 2005 rebate budget by nearly 25 percent to over $3.7 million for these programs.

Table C-3 – 2004 Budgeted Spending by Program

2004 Budgeted Spending By Program						
Storage Water Heating	Cycled AC	High Efficiency AC	Ground Source Heat Pumps	Interruptible Irrigation	C&I Interruptible	C&I Conservation Rebates
$ 2,686,660	$ 1,615,992	$ 1,513,673	$ 155,689	$ 144,755	$ 495,936	$ 1,075,045

APPENDIX D TRANSMISSION UPGRADES

The transmission work associated with the proposed project does not require a Certificate of Need because the transmission lines are not classified as Large High Voltage Transmission Lines (LHVTL). LHVTLs are transmission lines rated at 100 kV or more that are 10 or more miles in length or that cross state lines [Minn. Rules pt. 7849.0000, Minn. Statutes Section 216B.241]. The transmission information in this section is provided to help facilitate the understanding of the scope and magnitude of the transmission work associated with the project.

The Cambridge Station site has four existing 69-kV outlet lines and a large amount of increasing local load. Siting the plant in proximity to load minimizes the impact of adding generation on the regional transmission system. In order to determine the specific transmission impacts of the project, GRE submitted a request to the Midwest ISO (MISO) for a generation interconnection study to be completed. MISO contracted the study out to GRE's transmission division. The cover page and executive summary from the MISO study are included at the end of this appendix. The results show that the impacts for a plant in the 170 MW range are largely confined to the GRE 69-kV system in the general vicinity of the site. Specifically, the MISO study determined that the following four GRE 69-kV lines would be impacted by the plant addition:

- Cambridge-Dalbo-Princeton North-Princeton 22.64 miles
- Cambridge-Braham-Grasston 15.47 miles
- Cambridge-Rush Tap-Rush City 18.95 miles
- Cambridge-Cambridge Industrial-Isanti Tap-Athens 12.09 miles

GRE used the results of the MISO studies to determine what specific transmission upgrades would be necessary to remedy the impacts from the new generation. After further evaluation of the existing transmission systems, GRE determined that the 22.64-mile Cambridge-Dalbo-Princeton North-Princeton line segment warranted maintenance work as part of GRE's ongoing transmission maintenance program. Therefore, GRE determined that this section of transmission work would be completed regardless of whether or not the combustion turbine was installed. As such, the work associated with this transmission line is not considered to be part of the overall Cambridge project.

However, the description of that maintenance work is included in this appendix in order to provide a complete review.

D.1 Design Summary

GRE evaluated the transmission lines and determined that the work scope will include the demolition, and rebuild of all line segments. Reconstruction of all four lines is required since existing conductors on all transmission segments are undersized for the new capacity requirements of Cambridge Station. The lines were originally built using creosoted Southern Pine, Western Cedar, and Douglas Fir. Existing designs utilize pole heights ranging from 45 to 60 feet with spans averaging 300 feet.

Distribution line under-build exists on all of the transmission segments, and they will continue to be accommodated in each of the transmission design projects. GRE is working with East Central Energy and Connexus Energy, two of its member cooperatives, on the best approach for handling their customers when construction commences. East Central Energy is headquartered in Braham, Minnesota and Connexus Energy is headquartered in Ramsey, Minnesota.

New transmission designs will utilize 65 to 80 foot Western Red Cedar, and Douglas Fir species for poles. Laminate structures will be used for corners and angles when the ability for guying structures is compromised.

Designs include 477 ACSS, 26/7, stranded conductor with a 3/8” extra high strength shield wire. Lines will have a capacity rating of 135 MVA summer.

Transmission structures will be single pole, horizontal post with polymer insulators. A shield wire is positioned on the top of each structure.

Taller poles are employed due to the greater sag induced by the new, heavier conductor. The increase in pole height also provides for span distances in the range of 375 to 450 feet. Longer spans complement the landscape and make the design more attractive, since there will be fewer poles when compared with the current design.

D.1.1 Cambridge to North Princeton Transmission Project (OP Line)

The Cambridge to Princeton (OP) line situated in Isanti County, Minnesota was constructed in the late 1950s through early 60s, and includes 22.64 miles of transmission line

The OP Line will be completed in two segments when construction commences: from Cambridge to Princeton North and from Princeton North to Princeton. These segments were used to calculate the output benefit of the line relative to new generation placed in service. Section D.2 shows the total output benefit. The following is the segment breakdown:

Line Segment	Miles
Cambridge-Dalbo-Princeton North	20.77
Princeton North-Princeton	1.87

GRE has discussed design details with its member cooperative, East Central Energy, and plans to bury single phase distribution wire along the transmission right of way. GRE has researched the associated easements, which have been found to allow this plan.

Construction of this line segment is scheduled for June 2005.

D.1.2 Cambridge to Grasston Transmission Project (CM Line)

The Cambridge to Grasston (CM) line is situated in Isanti County and was constructed in the mid 1960s. This transmission segment includes 15.47 miles of transmission line. The current line exits Cambridge from the north, and continues this route 9.57 miles through Braham, MN, eventually reaching Grasston, 5.9 miles later.

The CM Line will be completed in two segments: from Cambridge to Braham and from Braham to Grasston. These segments were used to calculate the output benefit of the line relative to new generation placed in service. Section D.2 shows the total output benefit. The following is the segment breakdown:

Line Segment	Miles
Cambridge-Braham	9.57
Braham-Grasston	5.9

The new line construction will include updating the distribution circuits for East Central Energy. GRE has not yet determined whether the existing distribution line will remain overhead or be installed underground.

Construction of this line segment is scheduled for January 2006.

D.1.3 Cambridge to Athens Transmission Project (SC Line)

The Cambridge to Athens project is a 12.09-mile project that will exit the Cambridge plant site from the south and continue this path for 8.67 miles. At this point, GRE ties the City of Isanti load via a three-way switch placed inline on the circuit. The new transmission line then continues 3.42 more miles south and terminates into the newly constructed Athens switching station. GRE will work with Connexus Energy and East Central Energy on distribution requirements.

The SC Line will be completed in three segments: Cambridge to Industrial Park, Industrial Park to the Isanti Tap, and the Isanti Tap to Athens. These segments were used to calculate the output benefit of the line relative to new generation placed in service. Section D.2 shows the total output benefit. The following is the segment breakdown:

Line Segment	Miles
Cambridge-Industrial Park	2.5
Industrial Park-Isanti Tap	6.17
Isanti Tap-Athens	3.42

Construction of this line segment is scheduled for April 2006.

D.1.4 Cambridge to Rush City Transmission Project (RC Line)

The Cambridge to Rush City project is an 18.95-mile project that will exit the Cambridge plant site from the east and traverse eastward to Rush City.

The Cambridge to Rush City project will provide a secondary benefit by incorporating fiber optic cable for communications purposes that will complement completion of the GRE fiber telecommunications ring from Cambridge Station to Duluth.

The RC Line will be completed as one segment from Cambridge to Rush City when construction commences. This segment was used to calculate the output benefit of the line relative to new generation placed in service. Section D.2 shows the total output benefit. There is only one segment for the RC line.

Line Segment	Miles
Cambridge-Rush Tap-Rush City	18.95

Construction of this line segment is scheduled for January 2007.

D.2 Transmission Segment Rankings

When additional output is required from a power station that has multiple transmission lines, all lines must be considered for potential overloading since the rebuild of a single transmission line will not increase capacity or provide a specific amount of output capability. GRE's analysis shows that all four transmission lines that exit the Cambridge Station are impacted and must have segments completed before any additional generator output is allowed.

The table below represents the three levels of output achieved as GRE rebuilds segments of each transmission line. For each output level, all line segments represented in that level must be completed before the associated generation output can be realized.

Table D-1 – Levels of Output Achieved as GRE Rebuilds Segments of each Transmission Line

	Generation Output for New Unit	Priority	Transmission Line	Mileage
Output Level 1	0 to 52.5 MW	1	Cambridge-Industrial Park	2.5
Output Level 2	52.5 to 105 MW	2	Cambridge-Braham	9.57
		3	Cambridge-Dalbo-Princeton North	20.77
		4	Industrial Park-Isanti Tap	6.17
Output Level 3	105 to 179.4 MW	5	Braham-Grasston	5.9
		6	Cambridge-Rush Tap-Rush City	18.95
		7	Princeton North-Princeton	1.87
		8	Isanti Tap-Athens	3.42

GRE does not consider building only the segments associated with a certain level of output capability. One reason for this construction strategy is that GRE has sufficient time to complete transmission lines in their entirety before the plant needs the output capability. Also, GRE realizes efficiencies in the

design, cost, and construction when building long lines that have defined start and end points.

G361
Cambridge Station
Generation Capacity Addition

Interconnection Evaluation Study
for
Great River Energy

MISO Queue #37447-01

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November, 2004

1.0 Executive Summary

This report addresses the installation of the Cambridge Station, a natural gas peaking plant near Cambridge, Minnesota, which will be owned and operated by Great River Energy (GRE), of Elk River, Minnesota to serve its native load. The plant will consist of one machine with top output 190 MW. The summer maximum capability is expected to be around 170 MW. The results have shown that Cambridge Station will be a prudent development in the MAPP/MISO region with system response comparable or better than the existing system today.

Cambridge generation has an impact on the following transmission lines which will have to be rebuilt or reconductored to a higher capacity conductor, or have a temperature analysis for sag clearance:

- Cambridge-Dalbo-Princeton North-Princeton 22.64 mile, 69 kV line
- Cambridge-Braham-Grasston 15.47 mile, 69 kV line
- Cambridge-Rush Tap-Rush City 18.95 mile, 69 kV line
- Cambridge-Cambridge Industrial-Isanti Tap-Athens 9.01 miles, 69 kV line

Also, the existing substation bus, jumpers, and switches are underrated with the addition of the generation and are to be replaced with higher ampacity equipment.

With the Cambridge Station plant being designed for peaking purposes, it is expected that the transmission system will operate similar to existing conditions, except during periods of high load in the GRE service territory. One concern is that Cambridge Station is placed on the GRE 69 kV system which is a rather low voltage for such a large plant. However, the load served by this 69 kV system is significant such that power produced will basically stay in the 69 kV system.

GRE has designed transmission system improvements so that full unit output can be initially maintained during first contingency conditions. Reductions may need to be made on unit output to return the transmission system to a safe operating level if the contingency remains after a time period of 30 minutes. The critical outages are the loss of the 69 kV lines directly off the Cambridge 69 kV bus. The Cambridge Station facilities will provide voltage support to an area that has present voltage concerns during system intact and contingent situations.