5 PROJECT NEED AND PURPOSE

5.1 Summary of Need

The proposed Project is needed by 2017 to:

- Meet the in-service date for the proposed MPL Sebeka pump station that will be served by the proposed new Todd-Wadena Red Eye distribution substation.
- Address circuit overloads that currently exist on the Hubbard-Verndale 34.5 kV system and alleviate capacity issues identified on the lines between Hubbard and Verndale.

These needs are discussed in the sections below.

5.1.1 MPL Pump Station Need

MPL Reliability Project

The Minnesota Pipe Line Reliability Project will increase the pumping capacity on the MPL System's newest pipeline (MPL Line 4) to maintain reliable crude oil supplies to Minnesota refineries.

MPL is currently the only pipeline system supplying crude oil directly to Minnesota's two refineries: the Northern Tier Energy, LLC's Refinery in St. Paul Park, Minnesota and the Flint Hills Resources, LP's Refinery in Rosemount, Minnesota. These refineries are responsible for producing the vast majority of transportation fuels on which Minnesotans rely, and other essential products such as asphalt and home heating fuels. The refineries also help meet regional demand for these products, supplying significant percentages of the fuels used in surrounding states.

The MPL System is comprised of four pipelines that originate at a crude oil station in Clearbrook, Minnesota. The first pipeline in the system was installed in 1954. A second pipeline was built in the 1970s, and the third in the 1980s. The system was most recently expanded in 2008 with the addition of MPL Line 4 – formerly known as the MinnCan Project.

Today the MPL System has insufficient pumping capacity to maintain reliable crude oil supplies to the Minnesota refineries.

Since MPL Line 4 was built in 2008, both refineries have improved their utilizations and increased their operating capacity which, in turn, has increased demand on the MPL System. Wood River Pipeline, which had been capable of supplying Minnesota refineries with 90,000 barrels per day of crude oil, also has since been idled, shifting additional demand from the two Minnesota refineries to the MPL System.

As pipelines age, they also require more frequent inspections and maintenance, and occasionally must be taken out of service for extended periods of time to remain in good working condition. The MPL System currently lacks the pumping capacity needed to perform preventative maintenance on segments of the pipeline without disrupting crude oil supplies to Minnesota refineries. The MPL System also currently has insufficient sprint capacity, which is the ability to transport surplus barrels to refineries when needed to satisfy a sudden increase in demand or to make up for prior production or pipeline outages.

Supply disruptions caused by system outages, production constraints, or a lack of adequate pipeline capacity can have serious implications for local economies and people's daily lives. For example, in early 2014 a failure of a primary pipeline that supplies natural gas to Minnesota resulted in a sharp increase in prices, product rationing, and a prolonged shortage of home heating fuels. Similarly, in the summer of 2013, a series of regional refinery outages and system constraints caused record high gasoline prices in Minnesota and much of the Upper Midwest.

The continued reliability of the MPL System is critical to maintaining adequate supplies of the fuels Minnesotans and other Midwesterners depend on for transportation, home heating, powering motorized equipment, and numerous other applications.

MPL Line 4 was originally designed with a capacity of approximately 350,000 barrels of crude oil per day, but it currently transports approximately 165,000 barrels per day. The MPL Reliability Project will add six pump stations to MPL Line 4 and upgrade two existing stations to allow the pipeline to operate at its original design capacity. The total volume of crude oil reaching the market is not expected to change significantly as a result of this Project, but it will give MPL the flexibility to shift volumes to MPL Line 4 as needed to maintain reliable crude oil supplies and meet demand.

The expected maximum operating pressure of MPL Line 4 will not change as a result of the MPL Reliability Project. Rather, the pump stations will allow the pipeline to maintain a more consistent pressure across the entire 305 mile pipeline expanse.

The new pump stations will be located in rural areas along the MPL Line 4 route in Hubbard, Wadena, Morrison, Meeker, McLeod and Scott counties. No new pipeline will be constructed and no new ROW will be acquired for the MPL Reliability Project.

The proposed pump station related to the Menahga Area 115 kV Project is the "Sebeka" pump station in Wadena County.

The MPL System is operated and maintained by Koch Pipeline Company, L.P., which has a best-in-class program to inspect and repair pipelines through proactive reliability strategies. This includes an in-line integrity program and pump station equipment maintenance reliability programs.

The MPL Reliability Project is an estimated $125 million private investment that will bring increased property tax benefits to the counties where construction will occur. Additionally, 40 to 50 new construction jobs will be created as a result of the MPL Reliability Project. MPL anticipates using local contractors, as it does with most projects.

Gasoline, diesel, jet fuel, and other petroleum-based products remain essential to the economy. The MPL Reliability Project is critical to maintaining adequate supplies of these products while maintaining the long-term safety and reliability of the MPL System.

Sebeka Pump Station Electrical Needs

The electrical facility nearest the proposed Sebeka pump station is the Hubbard-Verndale 34.5 kV system. The Hubbard-Verndale 34.5 kV system is not robust enough to serve the pump station, which will include three 4500 horsepower electric motors that would create an electric demand of 10 MW at full output, as explained below.

When a motor is started, it typically draws a current 6-7 times its full load current for a short duration (commonly called the locked rotor current). During a motor start, there is a large increase in current that will result in a larger voltage drop across the system. This means that there can be large momentary voltage drops system-wide. If the system does not have a strong enough voltage source, the motor itself may not start. Meanwhile, the rest of the customers served from the same 34.5 kV system will see suppressed voltages.

Additionally, the Hubbard-Verndale 34.5 kV system does not have the capacity to serve 10 MW of electrical demand. The transition of Great River Energy's Menahga load from the 34.5 kV system to a new 115 kV system at the Blueberry Substation creates capacity on the Hubbard-Verndale 34.5 kV system, but not nearly enough capacity to serve the proposed 10 MW Sebeka pump station load.

Because it has been determined that the Hubbard-Verndale 34.5 kV system is not a feasible load-serving option for the proposed pump station, a new, larger voltage source at the Red Eye Substation is needed to provide reliable electric service to the pump station.

5.1.2 Load-Serving Need

Operational Contingencies

The Menahga Area 115 kV Project is required to address system overloads in the affected load area (**Figure 5-1**). System overload concerns are due to the growth of the peak electrical demand that has surpassed the level that can be served, and the age of the 34.5 kV sub-transmission lines combined with the overall length of the 34.5 kV network. The Project will also improve an aged sub-transmission infrastructure prone to operational concerns.

Maintaining the voltage of the power system is essential for the normal operation of electrical equipment connected to the power system. Electric appliances, for example, draw a large amount of current (above rated current) during low voltage conditions. This condition creates heat within the electric appliance that can damage the appliance. **Table 5-1** identifies the voltage criteria applied by substation owners and operators in the affected load area under both system intact and contingency conditions. Great River Energy and Minnesota Power both operate substations in the affected load area.

Figure 5-1. Affected Load Area

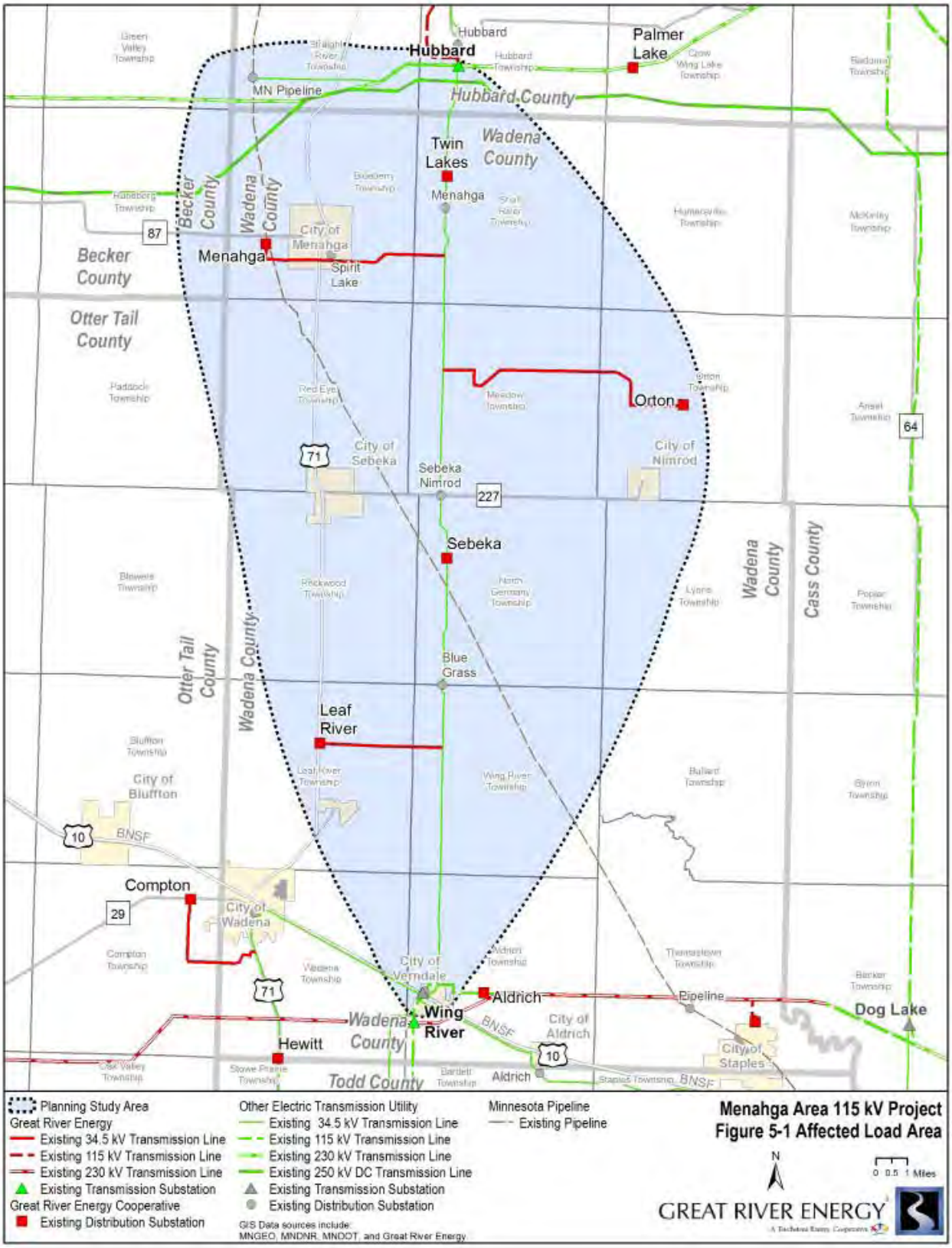


Table 5-1. Substation Voltage Criteria

Transmission System	System Intact		Contingency	
	Minimum Voltage (per unit)	Maximum Voltage (per unit)	Minimum Voltage (per unit)	Maximum Voltage (per unit)
Great River Energy	0.95	1.05	0.92	1.10
Minnesota Power	0.97	1.05	0.92	1.10

Transmission line and transformer overloads concerns relate to the amount of current operating through the conductor. Electrical equipment requires sufficient current to function properly. Conductors are rated to allow a certain amount of current to be carried. As electrical demand grows or when additional equipment is connected to the system, the conductor continues to supply the required current until the conductor reaches its maximum rating. An overload situation occurs when the conductor transfers current above its rating. In an overload situation, a conductor can heat up and begin to sag. Similarly, a transformer can overload and cause loss of life and/or fail catastrophically. If the overload condition is great enough or prolonged enough, the conductor can break. A break in a conductor can cause service interruption, equipment damage, or other system concerns. **Table 5-2** identifies the thermal loading criteria applied by transmission line owners and operators in the affected load area under both system intact and contingency conditions.

Table 5-2. Transmission Line Thermal Loading Criteria

Transmission System	Normal (percent)	Emergency (30 minutes) (percent)
Great River Energy	100	100
Minnesota Power	100	110

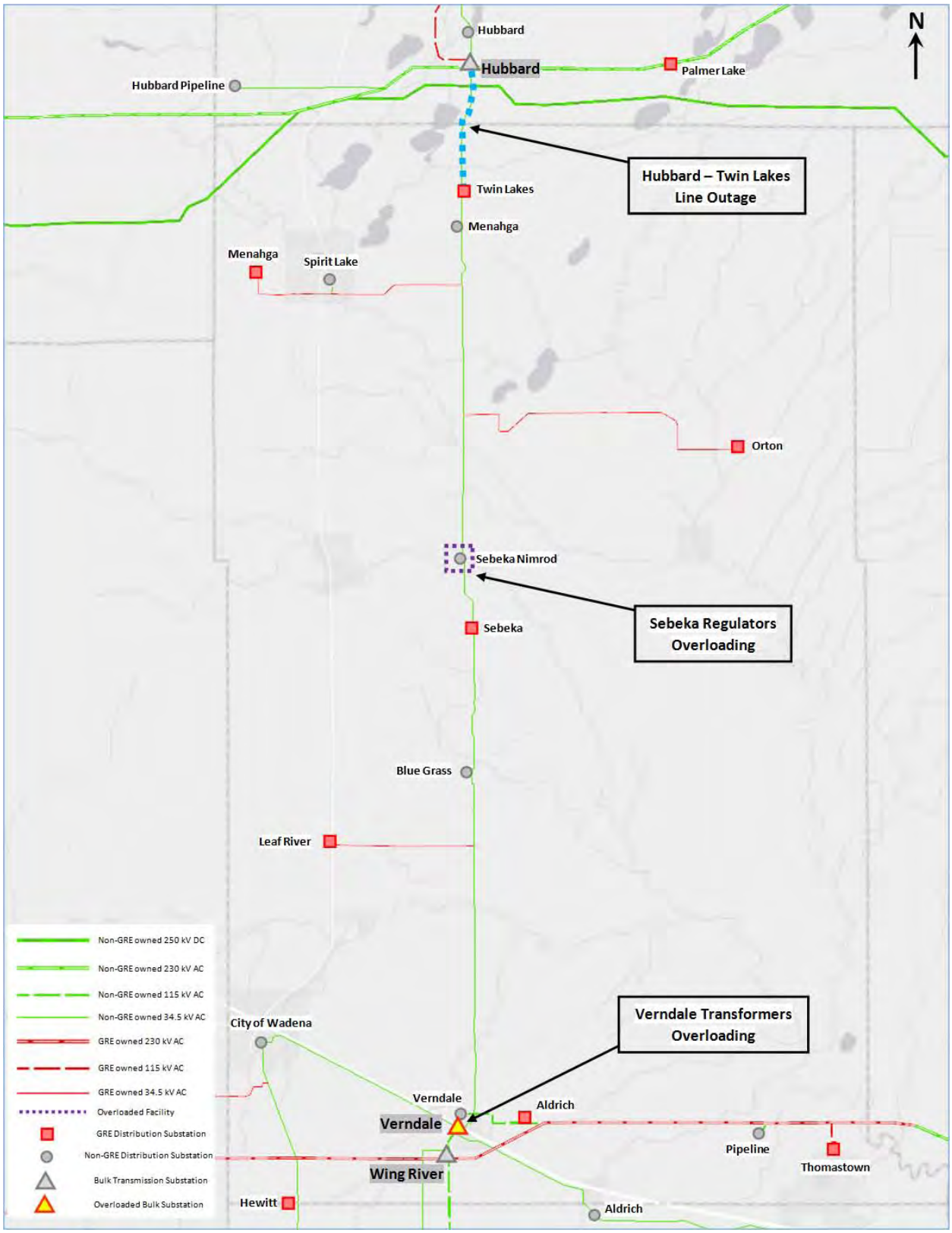
There are several single-system outages, when they occur, that lead to overloaded equipment in the study area, either a line or a transformer. Outages on the Hubbard-Twin Lakes or Verndale-Verndale distribution can lead to conditions that result in overloading lines and transformers, as described in next section.

<u>System Contingencies</u>

Hubbard-Twin Lakes 34.5 kV Outage

An outage of the Hubbard-Twin Lakes 34.5 kV sub-transmission line results in overloading of the Verndale transformers and the Sebeka Regulator Station. The outage of this particular line causes thermal overloads. These overload concerns are under existing system conditions. **Figure 5-2** identifies the substations and lines that experience these operational concerns during this contingency.

Figure 5-2. Hubbard-Twin Lakes 34.5 kV Outage with Existing System Conditions



Verndale-Verndale Distribution 34.5 kV Outage

An outage of the Verndale-Verndale 34.5 kV sub-transmission line results in an overload of the Hubbard-Twin Lakes 34.5 kV sub-transmission line. The outage of this particular line causes thermal overloads. These overload concerns are under existing system conditions. **Figure 5-3** identifies the substations and lines that experience these operational concerns during this contingency.

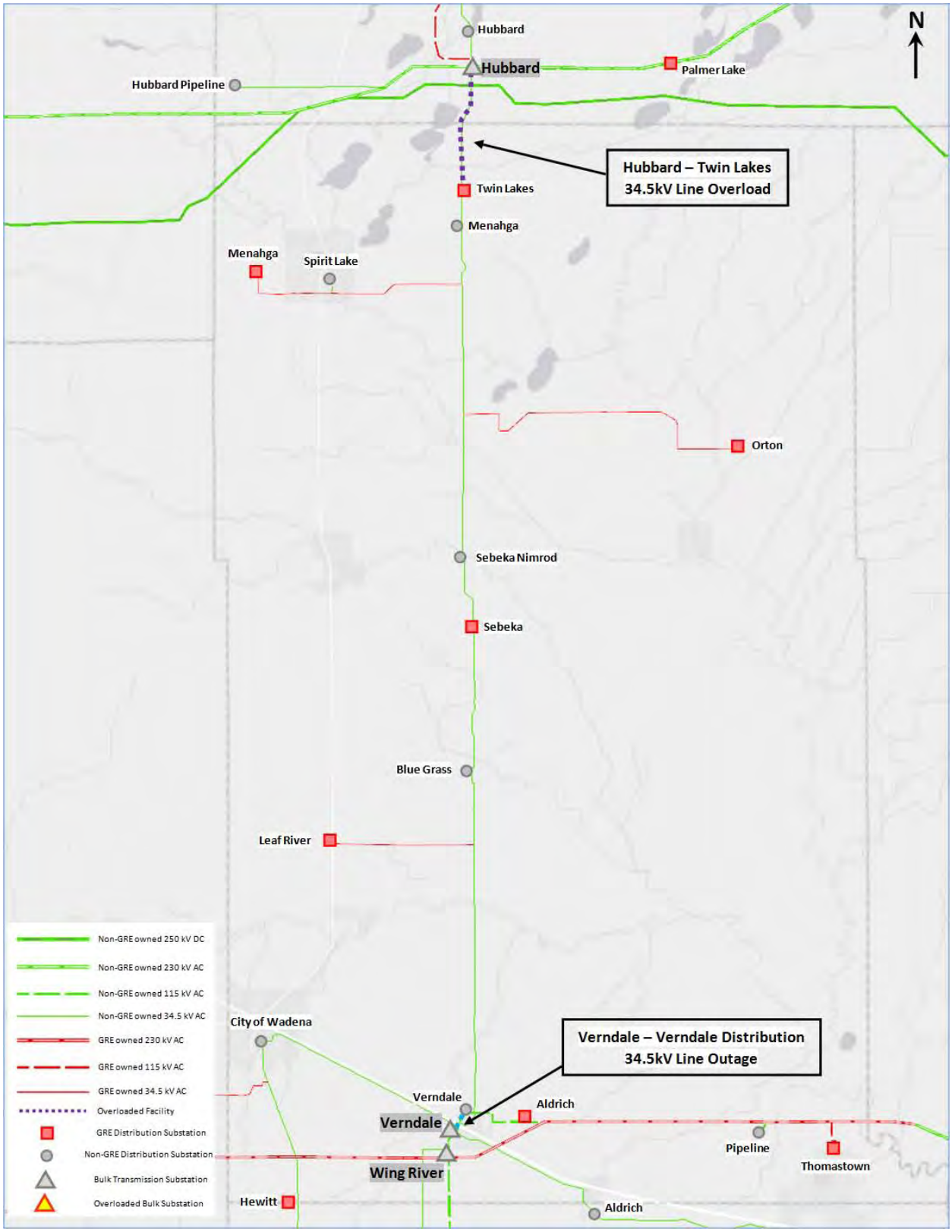
5.2 Relationship Between Proposed Project and Overall State Energy Needs

The need for this Project has been discussed in the Minnesota Biennial Transmission Projects Report since 2007 (Tracking Number 2007-NE-N3).

The proposed Project is a baseline reliability project that will insure a continuous supply of secure and reliable electric energy. The affected load area will benefit from the proposed Project. The benefit will be experienced in areas along CR 23 between Hubbard and Verndale including Menahga, Nimrod, Sebeka, Verndale and areas in between. This Project is consistent with the goals of the Minnesota Energy Security and Reliability Act that addressed a wide range of energy issues, including building the infrastructure necessary to deliver electric energy in a timely, efficient, secure, and reliable manner while at the same time minimizing cost and impact on the environment.

If the proposed Project or one of its alternatives is not constructed, the electrical needs of the proposed MPL Sebeka pump station could not be met. In addition, studies indicate that without the Project, electric security in the Project area would decrease, which could lead to reduced reliability. An insecure unreliable electric supply is not in the best interest of the area's residents or the State's; therefore, doing nothing would not be consistent with the energy policies of the State.

Figure 5-3. Verndale-Verndale Distribution 34.5 kV Outage with Existing System Conditions



5.3 Data Exemptions

On September 24, 2014, Great River Energy, on behalf of Applicants, submitted a Petition for Exemption to the Commission requesting that Applicants be exempted from certain filing requirements of the Minnesota Rules relating to information that must be included in a Certificate of Need application. The Commission, after soliciting and considering comments from interested persons, granted the exemption request on November 24, 2014, and issued its written Order on December 3, 2014. A copy of the Order is attached as **Appendix B**. In its Order, the Commission relieved Applicants from submitting certain information required under Minnesota Rules Chapter 7849 and specified other type of information that should be included in the CON application instead.

Applicants have included in this Application the information relating to the need for this Project required by the Minnesota Rules, as modified by the Commission in its Order granting the exemption request. The following summarizes the exemptions that were granted.

Minn. R. 7849.0260, Subps. A(3) and C(6). The Commission granted the request for an exemption from certain portions of Minnesota Rules 7849.0260, Subparts A(3) and C(6) requiring information on estimated line losses. The Commission authorized Applicants to provide line loss data for the system as a whole, rather than line loss data specific to the individual transmission lines.

Minn. R. 7849.0270, Subps. 1 and 2 (B-F). The Commission granted the request for an exemption from certain portions of Minnesota Rule 7849.0270 requiring information on predicted energy consumption for the utility's entire service area. Because the transmission upgrades proposed here are intended to serve the Hubbard-Verndale system, the Commission authorized Applicants to provide the requested data only for the affected load area. Historic demand data are provided for customers served from the Minnesota Power distribution substations and Great River Energy member cooperative substations in the affected load area that are relevant to the Project. Peak demand forecast was based on historical loading by substation, and growth rates of the affected load area that are part of the Minnesota Power and Todd-Wadena systems.

The Commission also exempted Applicants from providing data on forecasted consumption and peak demand by customer class (Minn. R. 7849.0270, Subps. 2(B) and 2(C)) for the northern portion of the Project. Instead, Applicants provided aggregate data on an annual coincident peak basis for the Minnesota Power and Todd-Wadena load in the Hubbard-Verndale system.

Because the southern half of the Project is needed to serve the proposed new MPL pump station, Great River Energy has provided information on the pump station to satisfy this rule.

The Commission exempted Applicants from providing information on the system peak demand by month as required in Minnesota Rule 7849.0270, Subpart 2(D). Instead of this information, Applicants have provided historical winter peak power demand data and forecast of power demand at each Minnesota Power substation and Todd-Wadena substation in the Hubbard-Verndale system that will benefit from the Project.

In lieu of providing the estimated annual revenue requirement per kilowatt hour for the system in current dollars (Minn. R. 7849.0270, Subp. 2(E)), the Commission granted Applicants' request to provide: 1) a description of how MISO spreads wholesale electricity costs among users of the transmission grid, and 2) the general financial effect of the Project on Great River Energy's member cooperatives and on Minnesota Power.

Minnesota Rule 7849.0270, Subpart 2(F) requires average system weekday load factors for each month. The Commission granted the exemption from this requirement because load factor is not relevant when evaluating the need for a transmission facility.

Minn. R. 7849.0270, Subps. 3-5 requires information on the forecast methodology employed, identification of databases, and details on the assumptions made in preparing the forecasts provided under Minnesota Rule 7849.0270, Subpart 2. Instead of this information, Applicants proposed providing substation load forecasts and line operation data. The Commission granted this exemption and Applicants have provided Minnesota Power and Todd-Wadena substation load data for those relevant substations within the Hubbard-Verndale system.

Minn. R. 7849.0280. The Commission exempted Applicants from the requirements of paragraphs B through G and I, as those sections apply to generation, not transmission proposals. The Commission also granted the request that the remaining requirements of Minnesota Rule 7849.0280, Subparts A and H, would be satisfied by providing information related to the affected load area for the Project.

Minn. R. 7849.0290. This rule requires an applicant to submit information about its conservation programs throughout its entire system. The Commission authorized Applicants to provide this information only for the applicable load area.

Minn. R. 7849.0300 and 7849.0340 requires detailed information regarding the consequences of delay on three specific statistically-based levels of demand and energy consumption. Applicants proposed to provide information regarding the consequences of delay in the context of the potential impacts on the local community's service reliability, and proposed to identify the threshold level of demand that places service at risk and the effect of incremental change in growth rather than evaluate system performance at three discrete demand levels. The Commission granted the requested exemption to these rules.

5.4 Affected Load Area

The customers that will benefit from the Project are primarily in Becker, Otter Tail, Wadena, and Hubbard counties.

Great River Energy has one member cooperative (Todd-Wadena) serving load in the affected load area from several substations. Todd-Wadena serves residential, commercial, agricultural and industrial customers in Becker, Otter Tail, Wadena, and Hubbard counties, including areas between Menahga, Sebeka, Nimrod, and Verndale. These areas will be benefit from the completion of the proposed Project.

Minnesota Power serves several areas in the affected load area. The load centers served by Minnesota Power in the affected load area include Menahga, Sebeka, Nimrod, and Verndale. These areas will directly benefit from the proposed Project.

5.5 Peak Demand and Annual Electrical Consumption

Minnesota Rule 7849.0270 requires an applicant for a CON to provide information about the peak demand and annual electrical consumption within the applicant's service area and system. Because the Project's transmission upgrades are designed to address localized system reliability issues, the Commission exempted Applicants from providing this information for their entire systems and authorized Applicants to provide the data only for the affected load area. Also, because there are small numbers of customers in the affected load area, the Commission agreed with Applicants that it was not necessary to provide the data for the various consumer classes served in the northern part of the Project and need only address customer class as it relates to the MPL pump station in the southern half of the Project. Finally, the Commission also agreed that the average system weekday load factor by month was not information that was required in this case.

5.5.1 Peak Demand

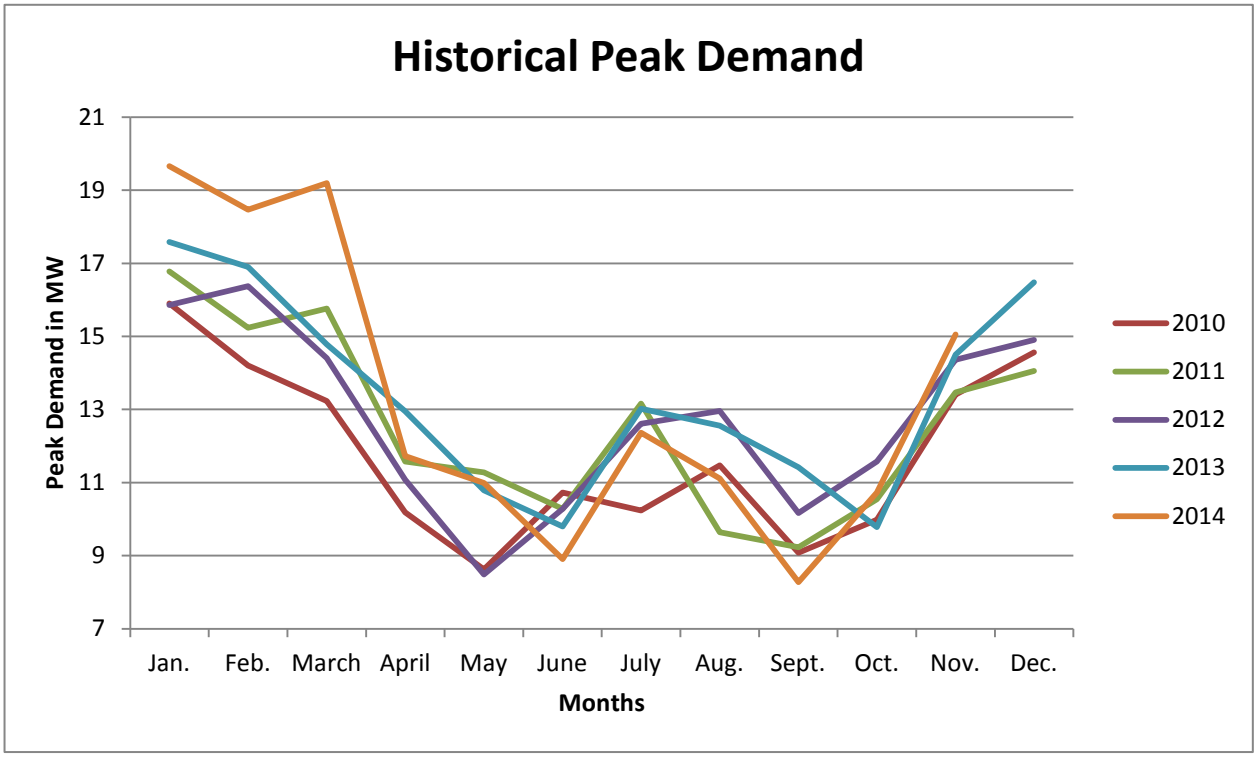
The peak demand for the affected load area for the previous five years is shown by month in **Table 5-3**. These peak demand values are based on the affected load area coincident peak demands.

Table 5-3. Historical Monthly Coincident Peak Demand for Affected Load Area (MW)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
2010	15.90	14.20	13.23	10.18	8.63	10.73	10.24	11.47	9.08	9.98	13.41	14.56
2011	16.78	15.24	15.76	11.58	11.28	10.28	13.16	9.64	9.23	10.54	13.47	14.05
2012	15.86	16.37	14.40	11.08	8.49	10.28	12.61	12.96	10.17	11.58	14.36	14.90
2013	17.58	16.90	14.78	12.95	10.79	9.80	13.02	12.56	11.42	9.78	14.50	16.48
2014	19.66	18.47	19.19	11.73	10.99	8.90	12.37	11.11	8.27	10.73	15.05	N/A

Figure 5-4 shows the plots of the historical monthly peak demand shown in **Table 5-3**. The figure shows the affected load area highest electric demand occurs in the months between November and March. These are winter season months and the study models were based on addressing the winter peak demand of the affected load area. The load forecasts are mainly for expected winter season peak demands, as there is no value in creating a projection for summer season.

Figure 5-4. Historical Monthly Peak Demand of the Affected Load Area (MW)



5.5.2 Annual Electrical Consumption

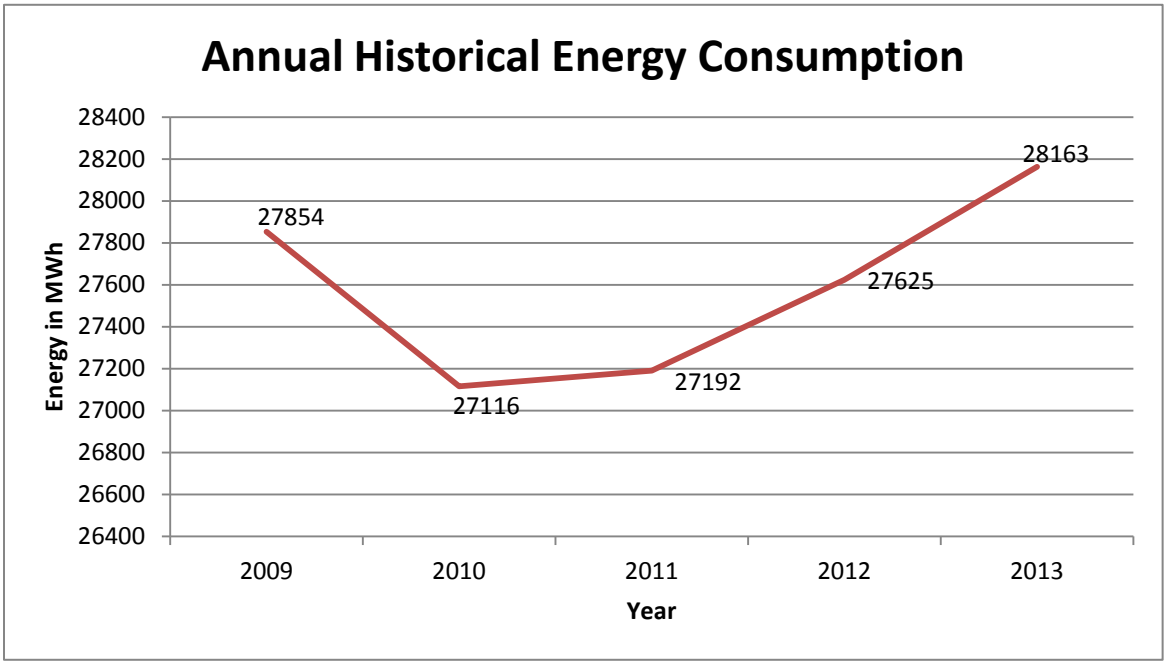
The total annual electrical consumption in MWh for Great River Energy and Minnesota Power loads in the affected load area for the previous five years is shown by month in **Table 5-4.**

Table 5-4. Historical Monthly Energy Consumption of Affected Load Area (MWh)

Year	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
2009	3337	2659	2626	2112	1860	1784	1934	1931	1919	2322	2304	3065	**27,854**
2010	3118	2623	2357	1888	1964	1814	2106	2102	1778	1943	2444	2979	**27,116**
2011	3072	2609	2618	2101	1885	1785	2325	2050	1847	1942	2291	2669	**27,192**
2012	2917	2889	2493	1901	1797	1823	2372	2013	1859	2270	2488	2804	**27,625**
2013	2978	2608	2608	2276	1910	1836	2169	2192	1850	2107	2478	3151	**28,163**

Figure 5-5 shows the annual historical energy consumption from 2009 through 2013 of the affected load area. Over this 5-year period, the annual average growth rate in energy consumption was 0.3 percent.

Figure 5-5. Five-Year Historical Annual Energy Consumption of the Affected Load Area



5.6 Forecasts

Minnesota Rule 7849.0270 requires an applicant to explain the manner in which the applicant has conducted forecasting of its future energy needs. In the current filing, the Commission granted certain exemptions as summarized in **Section 5.3** and included in **Appendix B**, which is expected to result in a more streamlined filing focusing on the elements of the forecast that are more relevant to the need for the facilities. The affected load centers are mostly served by Great River Energy and Minnesota Power. The load forecasting methodology used by Applicants when determining the need for the proposed transmission Project is discussed in **Section 5.6.1**.

5.6.1 Methodology

When developing the long-range load forecast of the area for the affected load area, multiple load forecasts scenarios were compared. A more conservative load forecast, which has a high probability of occurring in the system, was chosen for the study. In fact, the existing and projected load profile and type of customers, such as residential, agricultural, commercial or industrial of the affected load area are different from one area to another. To be more predictive of the load growth trends at a specific load center in the affected load area, more emphasis was given to forecast loads based on growth rate by individual distribution substations.

<u>Great River Energy (Todd-Wadena)</u>

Great River Energy member cooperative Todd-Wadena serves the majority of the load centers in the affected load area. The following data were analyzed and compared when determining the growth rate percentage and projected peak load data for loads served by Todd-Wadena:

1. Past 10-year historical cooperative coincident peak load data and growth rate;

2. Recent 5-year historical cooperative peak load data and growth rate; and

3. Average annual growth rate per substation as forecasted by Great River Energy and Todd-Wadena.

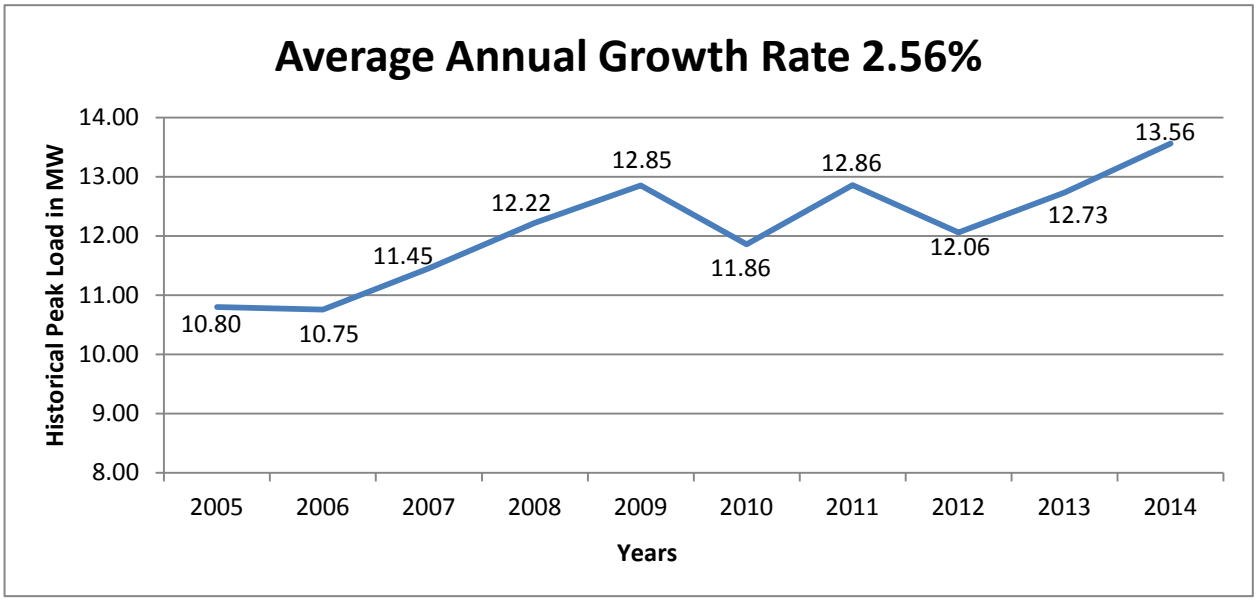
Great River Energy retrieved 10 years of historical coincident peak load data for the affected load centers served by Todd-Wadena. The historical coincident peaks are chosen so that switching peaks due to transferring loads between substations are removed when determining the peak demand at a substation. Note that switching peak is a peak demand at a substation when load is transferred to the substation from another substation by switching feeders. This mostly occurs during contingencies in the distribution system. **Table 5-5** shows the 10 years, from 2005 through 2014, recorded historical coincident peak demands in MW for the affected load area served by Todd-Wadena.

Table 5-5. Affected Load Area 10-Year Historical Coincident Peak Load Served by Todd-Wadena (MW)

Substation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Sebeka	1.958	2.077	2.182	2.312	2.570	2.214	2.425	2.237	2.247	2.498
Menahga	3.389	3.412	3.855	3.907	4.210	3.396	3.654	3.495	3.662	3.974
Leaf River	2.786	2.605	2.690	3.058	3.189	3.190	3.426	3.001	3.287	3.433
Twin Lakes	1.008	0.978	0.985	1.015	0.944	1.324	1.507	1.493	1.526	1.550
Orton	1.659	1.682	1.741	1.927	1.941	1.737	1.844	1.833	2.010	2.106
Total	**10.80**	**10.75**	**11.45**	**12.22**	**12.85**	**11.86**	**12.86**	**12.06**	**12.73**	**13.56**

Figure 5-6 depicts the annual growth trend of the affected load area peak demand for the past ten years for loads served by Todd-Wadena. **Figure 5-6** illustrates that the peak load demand for the Todd-Wadena loads in the affected load area has shown consistent growth starting in 2005 and onward. The peak demand average annual growth rate of the affected load area served by Todd-Wadena for the prior 10 years is about 2.56 percent.

Figure 5-6. Affected Load Area Served by Todd-Wadena-10-Year Historical Coincident Peak Demand Growth Trend



Great River Energy also looked at historical peak demands of the affected load area for the past five years to get a more descriptive trend of the peak load growth rate of the affected load area for the near-term. The five-year historical load growth rate portrays the near-term peak load growth trend of the affected load area better than the growth rate based on the 10-year historical data. **Table 5-6** shows the five years, from 2010 through 2014, historical coincident peak loads recorded in the system.

Table 5-6. Affected Load Area Five-Year Historical Coincident Peak Load Served by Todd-Wadena (MW)

Substation	2010	2011	2012	2013	2014
Sebeka	2.214	2.425	2.237	2.247	2.498
Menahga	3.396	3.654	3.495	3.662	3.974
Leaf River	3.190	3.426	3.001	3.287	3.433
Twin Lakes	1.324	1.507	1.493	1.526	1.550
Orton	1.737	1.844	1.833	2.010	2.106
Total	**11.86**	**12.86**	**12.06**	**12.73**	**13.56**

The annual peak load demand of the affected load area in **Table 5-6** is plotted in **Figure 5-7** to graphically illustrate the peak load growth trend from 2010 through 2014.

Figure 5-7. Affected Load Area Five-Year Historical Coincident Peak Load Growth Trend – Todd-Wadena

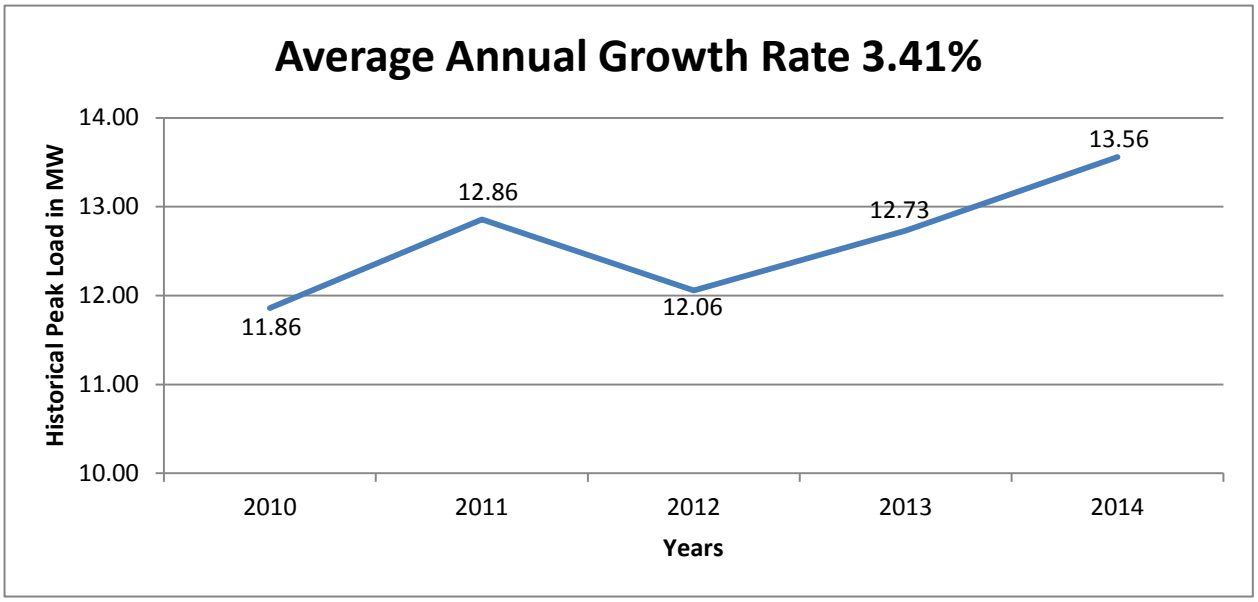


Figure 5-7 shows consistent growth of the peak demand for the affected load area served by Todd-Wadena. The historical peak load average annual growth rate was calculated to be about 3.41 percent.

Great River Energy also considered the load growth percentage as forecasted by Todd-Wadena. The load projection was done for individual substations that serve the affected load area. The load projection takes into account the projected land use data that are available from city and county agencies in Todd-Wadena's service territory. The number of new residential, commercial and industrial consumers for each substation was projected as part of long range load forecast analysis. **Table 5-7** shows the projected average annual load growth percentages for each substation.

Table 5-7. Forecasted Average Annual Growth Rate

Todd-Wadena Substations	Annual Growth Rate
Sebeka	1.00%
Menahga	1.00%
Leaf River	1.00%
Twin Lakes	1.00%
Orton	1.00%

When determining the average annual growth rates for forecasting the future peak demand of the affected load area, Great River Energy compared the three percentage growth rates (the ten year, five year and the weighted annual average growth rate) from the data provided by Todd-Wadena. The 10-year historical peak load data showed an average annual growth rate of 2.56 percent, the five-year historical peak load data showed an average annual growth rate of about 3.41 percent

and the load projection of individual substations by Todd-Wadena showed a weighted average annual growth rate of 1.0 percent. The weighted average annual growth rate was calculated based on the following formula and uses the 2014 historical substation peak loads from **Table 5-5**.

$$\text{Weighted average annual growth rate} = \frac{\text{LC P\#1}*\%\text{GR1}+\text{LC P\#2}*\%\text{GR2}+\text{LC P\#3}*\%\text{GR3}+\cdots\text{etc}}{\text{LC P\#1}+\text{LCP\#2}+\text{LCP\#3}+\cdots\text{etc}}$$

Where: LCP# 1 = Historical Peak Load of Load Center 1 (Substation 1)

LCP# 2 = Historical Peak Load of Load Center 2 (Substation 2)

%GR1 = % percentage growth rate substation #1

%GR2= % percentage growth rate of substation # 2

With the power system showing inadequacies under recent historical peak load during contingencies, it was decided to use a conservative growth rate with which the forecasted peak load has the high probability of occurring on the years for which it is forecasted. The weighted average annual load growth rate produced from Todd-Wadena's load growth rate forecast (**Table 5-7**) showed a weighted annual average annual growth rate that is not as high as the historical five-year average annual growth rate or the ten year historical average annual load growth rate. Therefore, the peak demand of the affected load area will be forecasted using the average of the three forecasted annual growth rate percentages (2.32 percent) for loads served by Todd-Wadena, and individual substation peaks are forecasted using the growth rate provided for each substation in **Table 5-8**. This table shows the forecasted 2017/18 load levels per substation used when determining the need for the proposed Project. The starting load for the load forecast is the 2014 peak load recorded at each substation serving the affected load area.

Table 5-8. Forecasted 2018 Load Levels Used for the Out-Year Study

Todd-Wadena Substations	Winter Peak – 2013/14 Load		Applied Growth Rate	Winter Peak – 2017/18 Load	
	MW	MVAR		MW	MVAR
Sebeka	2.498	0.105	1.00%	2.599	0.109
Menahga	3.974	-0.053	1.00%	4.135	-0.055
Leaf River	3.433	0.070	1.00%	3.572	0.073
Twin Lakes	1.550	-0.077	1.00%	1.613	-0.080
Orton	2.106	-0.050	1.00%	2.192	-0.052
Total	**13.561**	**-0.005**	**-**	**14.112**	**-0.005**

Minnesota Power

Minnesota Power provides service in the affected load area though five distribution substations, Verndale, Blue Grass, Menahga, Sebeka-Nimrod, and Spirit Lake. Similar to the load forecast for affected area load served by Todd-Wadena, a conservative growth rate was used when forecasting affected area load served by Minnesota Power. The historical peak load growth of the affected load area served by Minnesota Power grew in the same trend as the affected load area served by Todd-Wadena. **Table 5-9** shows the 9-year historical load recorded for the substations in the affected load area served by Minnesota Power.

Table 5-9. 9-Year Historical Coincident Peak Load Data for Affected Load Area Served by Minnesota Power (MW)

Substation	2006	2007	2008	2009	2010	2011	2012	2013	2014
Verndale	0.819	0.890	0.736	0.742	0.658	0.507	0.779	0.899	1.138
Blue Grass	0.043	0.046	0.038	0.039	0.034	0.026	0.040	0.047	0.059
Menahga	0.375	0.421	0.390	0.495	0.389	0.395	0.490	0.454	0.473
Spirit Lake	1.636	1.834	1.699	2.159	1.695	1.721	2.136	1.978	2.063
Sebeka	1.216	1.364	1.263	1.605	1.260	1.279	1.588	1.470	1.534
Total	**4.089**	**4.555**	**4.126**	**5.040**	**4.036**	**3.928**	**5.033**	**4.848**	**5.267**

Figure 5-8 shows that the customer load in the affected load area served by Minnesota Power grew at an average annual rate of 2.85 percent in the last nine years (2006 – 2014). Similarly, the plot of the five-year historical peak loads, **Figure 5-9**, shows that the affected load area grew at average annual rate of 5.48 percent between 2010 and 2014.

The growth rate of the peak loads in affected load area served by Minnesota Power is growing at a faster rate than the growth rate used when studying and justifying the need for the proposed Project. The proposed Project is based on a conservative average annual growth rate of 1 percent that was applied to Minnesota Power's 2014 peak load. A one percent annual growth rate was applied to the 2013/14 peak loads when forecasting and modeling the 2017/18 (out-year) load level of the affected load area served by Minnesota Power. **Table 5-10** shows the 2013/14 peak loads recorded for Minnesota Power substations serving the affected load area, the applied growth rate and the forecasted 2017/18 load level. It should be noted that use of either nine or five-year historical load growth percentage would result in higher 2017/18 load levels than shown in **Table 5-10.**

Figure 5-8. Affected Load Area Nine-Year Historical Peak Demand Growth Trend Served by Minnesota Power

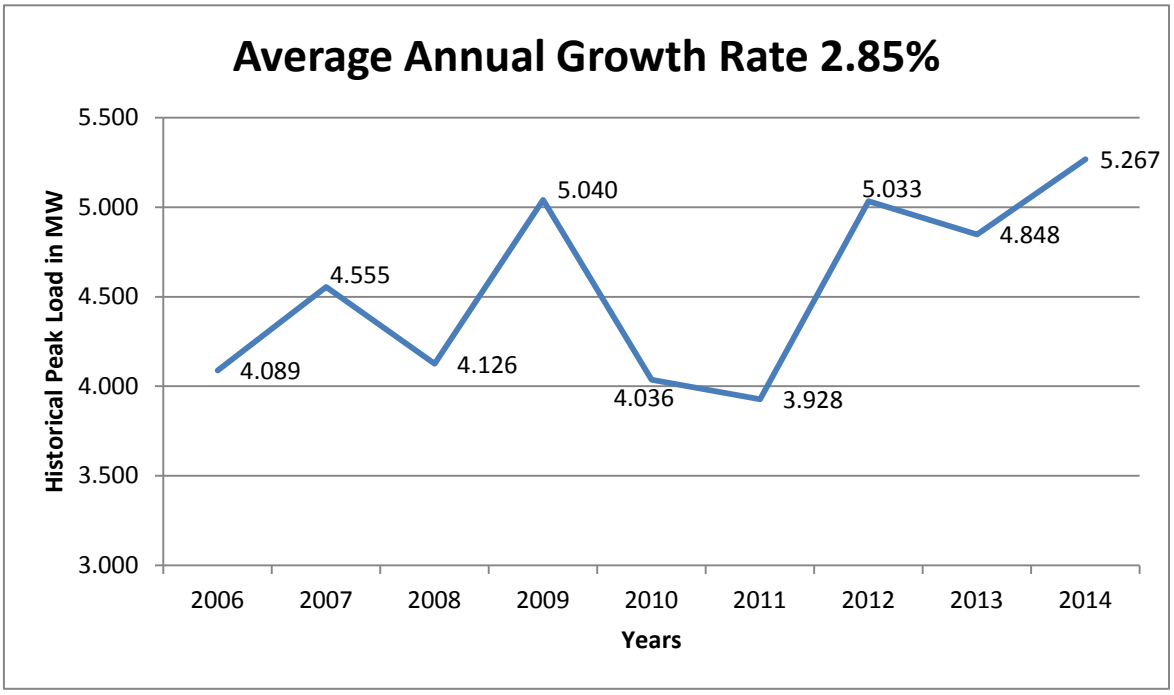


Figure 5-9. Affected Load Area Five-Year Historical Peak Demand Growth Trend Served by Minnesota Power

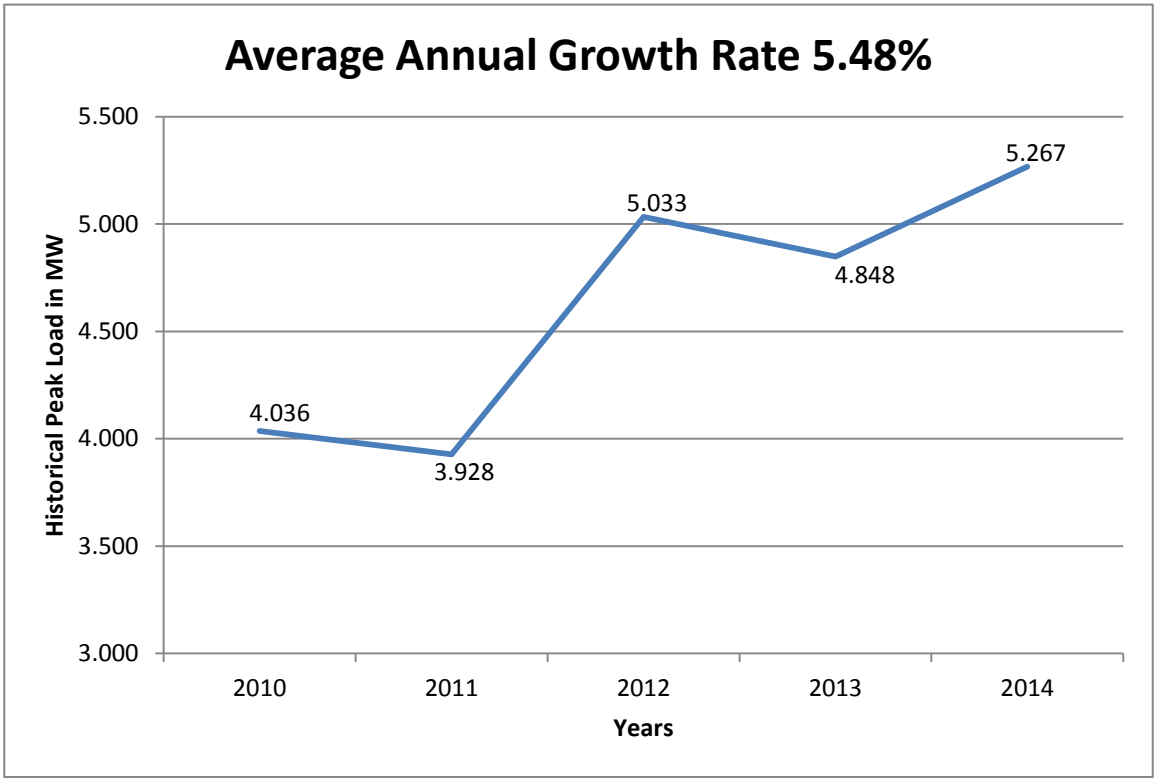


Table 5-10. Forecasted 2018 Load Levels Used for the Out-Year Study

Minnesota Power Substations	Winter Peak-2013/14 Load		Applied Growth Rate	Winter Peak-2017/18 Load	
	MW	MVAR		MW	MVAR
Verndale	1.138	0.231	1.00%	1.184	0.240
Blue Grass	0.059	0.012	1.00%	0.061	0.012
Menahga	0.473	0.096	1.00%	0.492	0.100
Spirit Lake	2.063	0.419	1.00%	2.147	0.436
Sebeka	1.534	0.311	1.00%	1.596	0.324
Total	**5.267**	**1.069**	**-**	**5.481**	**1.112**

The peak demand projection was made for the winter season using the recorded historical peak of the 2013-2014 season as the starting point. The weighted average annual load growth percentage, which is calculated from the 2014 historical substation peak demand and substation growth rates in **Table 5-8** and **Table 5-10,** is used to forecast the peak demand shown in **Table 5-11**.

Table 5-11. Winter Season Forecast Peak Demand per Year in MW (Todd-Wadena and Minnesota Power)

Winter Season	Peak Demand	Weighted Average Annual Growth Rate
2013-2014	18.83	-
2014-2015	19.02	1.00%
2015-2016	19.21	1.00%
2016-2017	19.40	1.00%
2017-2018	19.59	1.00%
2018-2019	19.79	1.00%
2019-2020	19.99	1.00%
2020-2021	20.19	1.00%
2021-2022	20.39	1.00%
2022-2023	20.59	1.00%
2023-2024	20.80	1.00%

The maximum peak demand was calculated based on the five-year hourly historical peak demand data. To eliminate switching peaks, the coincident peaks were calculated for each month as provided in **Table 5-3**. The winter coincident peak load of the affected load area was found to be 18.83 MW, which was observed in January 2014. This peak demand and the weighted average annual growth rate are used when forecasting the winter peak demand of the affected load area from winter 2013-2014 through winter 2023-2024 as shown in **Table 5-11**. The weighted average annual load growth rate is calculated to be 1.0 percent.

The recorded 2013/14 historical energy consumption of the affected load area was used as a starting point when forecasting energy consumption for the affected load area. For purposes of studying the transmission system and monitoring load growth, distribution substation data are used to calculate and forecast load. These distribution substations are closer to the load than bulk substations and the data from distribution substations are more reflective of load patterns. The growth rate used for forecasting energy is calculated from the historical five year (2009/10-2013/14) annual energy usage data. The average annual energy growth rate of the affected area in the past five years is calculated to be 0.3 percent.

5.6.2 Demand Forecast Results

Table 5-11 shows Applicants' results of forecasting peak demand in the affected load area from winter 2013-2014 through winter 2023-24.

5.6.3 Consumption Forecast Results

Table 5-12 shows Applicants' results of forecasting energy consumption in the affected load area from 2013 through 2023.

Table 5-12. Forecasted Annual Energy Consumption (Todd-Wadena and Minnesota Power)

Year	Energy (MWh)	Growth Rate
2013	28,163.00	-
2014	28,247.49	0.30%
2015	28,332.23	0.30%
2016	28,417.23	0.30%
2017	28,502.48	0.30%
2018	28,587.99	0.30%
2019	28,673.75	0.30%
2020	28,759.77	0.30%
2021	28,846.05	0.30%
2022	28,932.59	0.30%
2023	29,019.39	0.30%

5.6.4 System Capacity

Minnesota Rule 7849.0280 provides that an applicant for a CON must provide information about the ability of the existing system to meet the demand for energy predicted to occur in upcoming years. Applicants applied for an exemption from most of the requirements in this rule because they are applicable to proposed generating plants, not transmission lines. The Commission granted the exemption. The only two provisions in the rule that Applicants must respond to are subpart A (relating to planning programs) and subpart H (relating to net demand and net capability). Those discussions are provided below.

5.6.5 Transmission Planning/Net Demand and Net Capability

Great River Energy was part of the Minnesota Transmission Owners that prepared the 2007 Biennial Transmission Projects Report, which discussed a need for improvement in the affected load area and provided alternatives considered for addressing the inadequacies (tracking number 2007-NE-N3). More recently, Great River Energy cancelled Project 2007-NE-N3, submitted in the 2007 Biennial Transmission Projects Report, and replaced it with Project 2013-NE-N21, which was submitted in the 2013 Biennial Transmission Projects Report.

Load duration curves were developed to illustrate the number of hours the affected load area is exposed to inadequacies in the system. **Figure 5-10** shows the load duration curve for 2013/14 and five years of forecasted load duration curves. The forecasted load duration curves are based on the 2013/14 historical hourly flows record in the system and the weighted average annual growth rate of 1.0 percent.

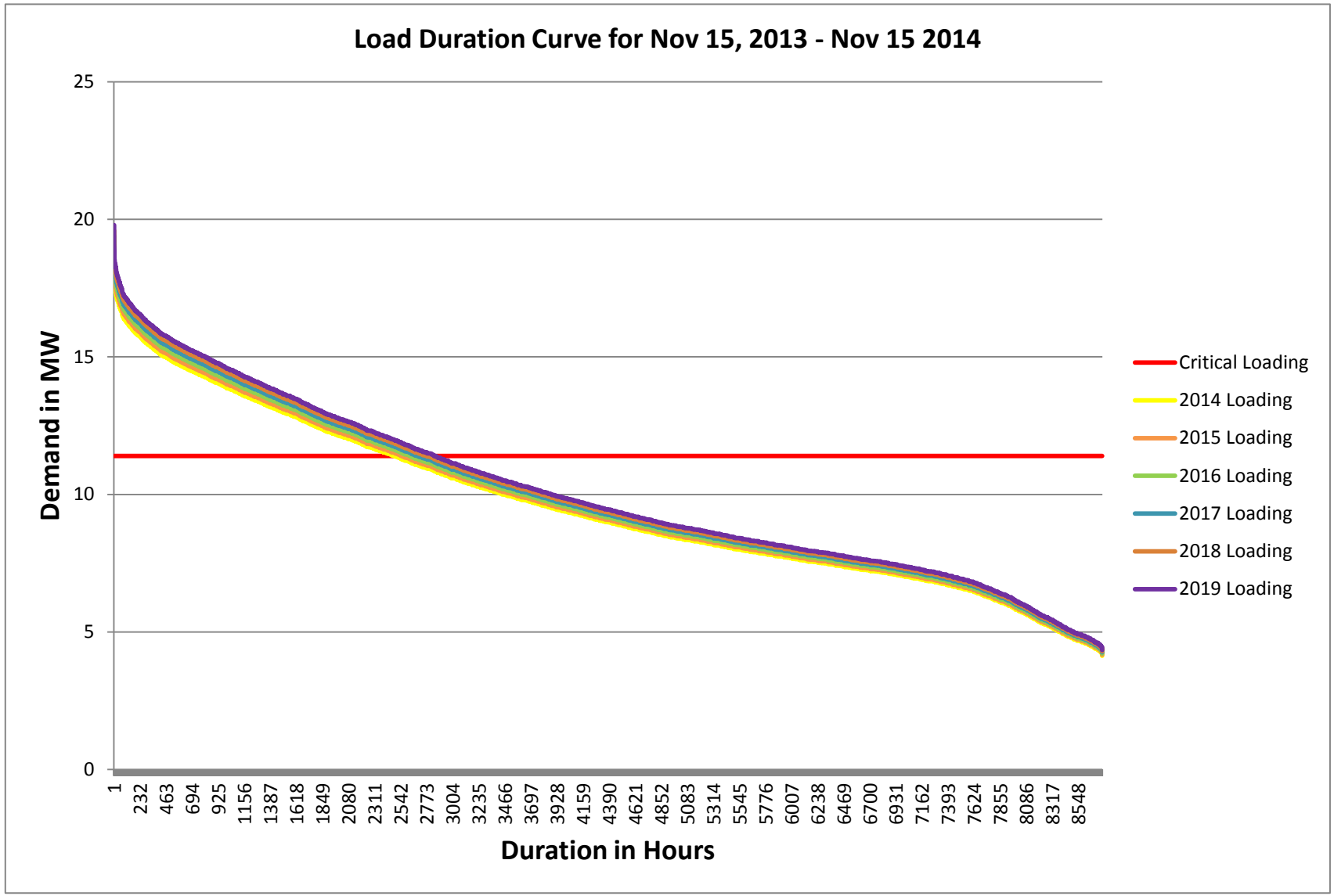
The system analysis showed that the existing transmission system serving the affected load area can reliably serve loads up to 11.39 MW level. The area was found at risk to experience thermal overloads during critical contingencies when the peak load of the affected load area exceeds the critical load level of 11.39 MW. The load duration curve shows that the system was at a risk of experiencing thermal overloads in the 2014 for about 2485 hours of the year.

Table 5-13 summarizes the number of hours the system will be at risk of experiencing inadequacies without the Project.

Table 5-13. Duration that the Affected Load Area is at Risk of Experiencing Inadequacies (Todd-Wadena and Minnesota Power)

Year	Duration at risk (hours)
2014	2485
2015	2550
2016	2632
2017	2699
2018	2773
2019	2839

Figure 5-10. Load Duration Curve – Todd-Wadena and Minnesota Power



Applicants conducted computer modeling of various alternatives designed to address the identified electric system inadequacies to determine what the impact on the system would be under various operating conditions and contingencies. The modeling showed that the development of a single circuit 115 kV line from Hubbard to the proposed new Blueberry 115/34.5 kV Substation, converting the Todd-Wadena Menahga Substation to 115 kV service, and constructing a radial 115 kV line to the proposed new Red Eye Substation in the 2017 timeframe would provide adequate and reliable service in the area up to the 2032, given anticipated growth levels. **Figure 5-11** shows the increase in available capacity of the transmission system with the proposed Project versus peak demand.

Figure 5-11. Capacity of the Affected Load Area Transmission System with the Proposed Project versus Peak Demand (Todd-Wadena and Minnesota Power)

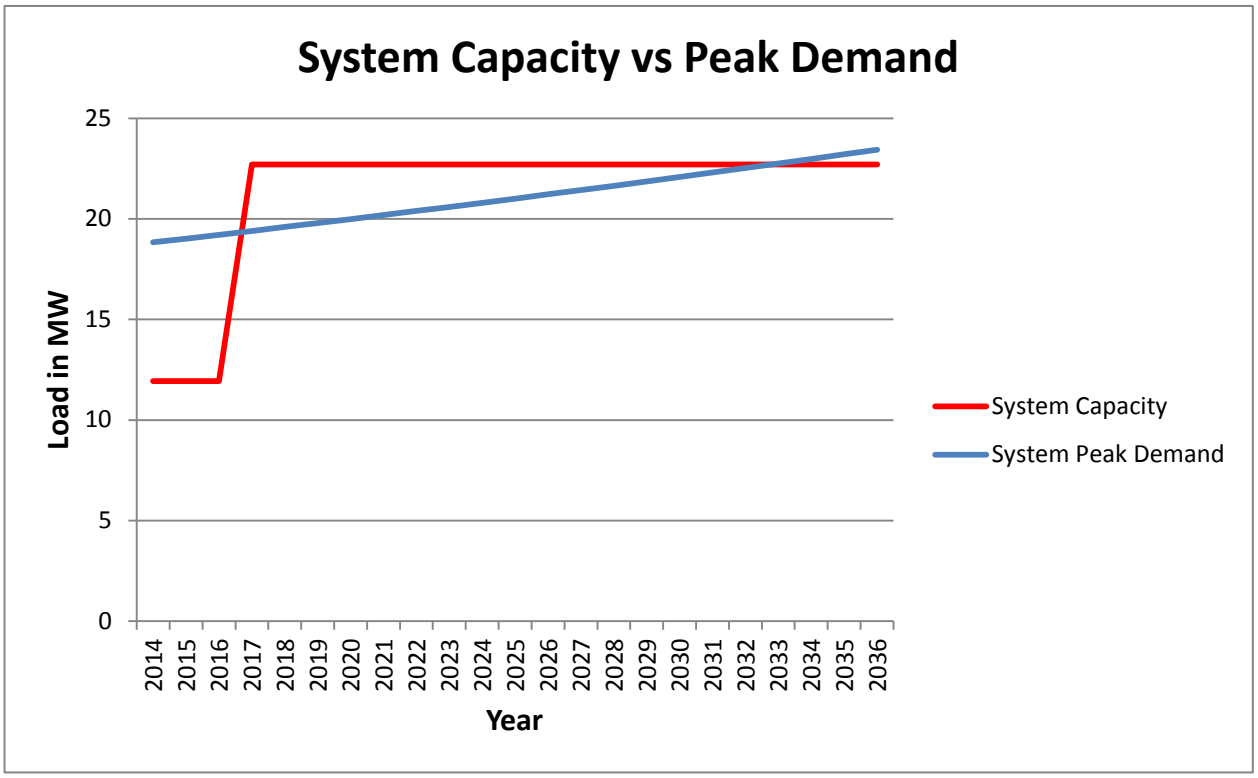


Figure 5-11 shows that transmission capacity follows the load growth of the affected load area provided that the load growth in the system will sustain as forecasted.

5.7 Increased Efficiency

The proposed Project includes building a new 115 kV circuit from Hubbard to the Menahga area and creating a new source to the Hubbard-Verndale 34.5 kV system at the Blueberry Substation. Menahga will be removed from the 34.5 kV system and will be served via the new 115 kV line from Hubbard. After the Project, Menahga will no longer create a power flow demand on the 34.5 kV system, which is more lossy than the 115 kV system. Placing the new 115/34.5 kV Blueberry source in between the Verndale and Hubbard sources creates a reduced flow of power from Hubbard and Verndale. Relocating a source closer to the loads will result in sending power over shorter distances. Therefore, the proposed Project, in general, increases the efficiency of the transmission system and results in annual loss savings of approximately 0.3 MW and annual energy savings of 977.7 MWh annually as discussed in **Section 4.5**.

5.8 Load Management and Energy Conservation Programs

5.8.1 Load Management

Pursuant to Minn. Stat. §216B.2422, Great River Energy and Minnesota Power have submitted separate Resource Plans to the Commission. These Resource Plans detail, among other things, Applicants' programs to manage customer demand and energy consumption. As a part of this effort, each of the "demand side management" (DSM) programs are directed at minimizing peak load conditions by reducing the load of participating customers at system peak conditions.

Current Great River Energy DSM activities include interruptible demand programs, off-peak storage programs and Conservation Improvement Program (CIP) programs offered in partnership with Great River Energy's member-owners. In aggregate, the load management programs for the entire Great River Energy system curtail an estimated 15 percent of maximum seasonal peak demand (360 MW summer/320 MW winter).

Current Minnesota Power DSM activities include the CIP along with Dual Fuel, Controlled Access, and Interruptible Rates.

The impact of the load management program is included in the Great River Energy and Minnesota Power load forecasts, and do not provide enough capacity to delay or avoid the need for the proposed facilities.

5.8.2 Energy Conservation

<u>Great River Energy</u>

Great River Energy has a robust portfolio of rebate programs, promotions and energy efficiency expertise. These programs help Great River Energy achieve the requirements outlined in Minnesota Statutes Section 216B.241. In 2013, Great River Energy and its member cooperatives invested approximately $19.8 million in the energy efficiency, conservation and DSM programs.

Great River Energy and its member owners not only provide rebates to meet the Minnesota Energy Conservation Policy goals, but also consider energy conservation and load management as an important resource in the planning process. Individual member-system participation goals

are used in conjunction with Great River Energy's diversified demand assumptions and loss factors to calculate total system peak reduction. Great River Energy's goal is to maintain and enhance existing programs and continue to introduce new programs that provide net benefits to cooperative members, cooperatives and Great River Energy. The programs are designed to save natural resources and delay the need for additional transmission and/or generation resources.

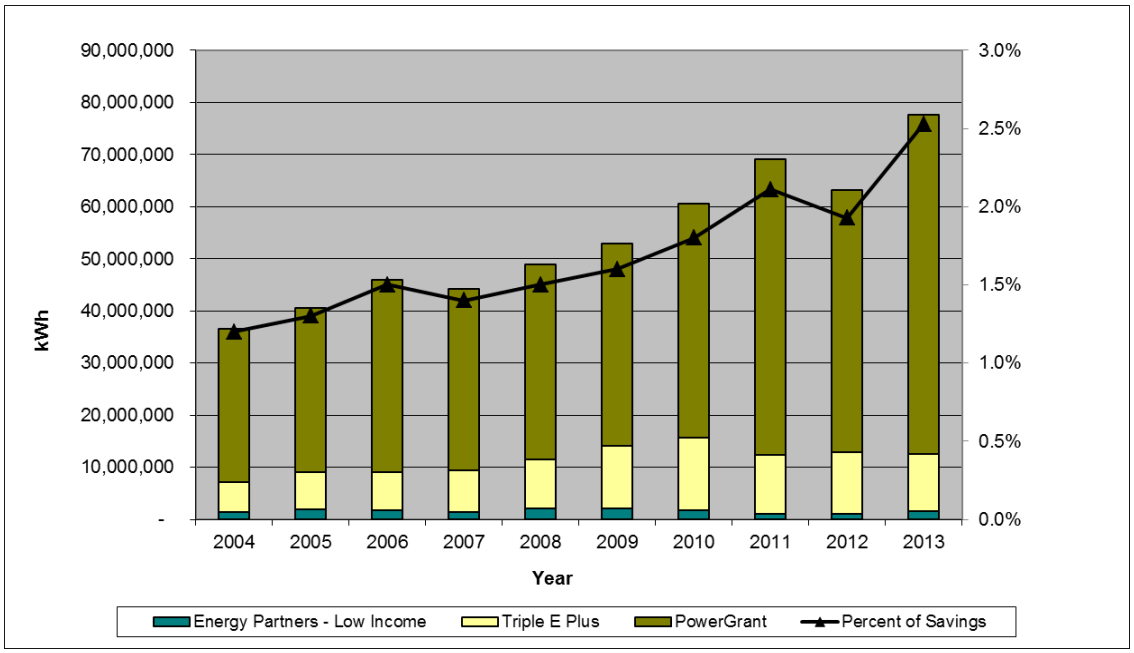
Great River Energy's conservation programs are described in more detail in **Appendix I**.

Minnesota Power

Minnesota Power's CIP remains part of core service offerings and is highlighted as part of its *Energy***Forward** resource strategy.[2] CIP focuses on increased efficiencies that reduce the amount of energy needed for certain uses and processes. Minnesota Power's CIP includes residential, commercial, and small scale renewable programs.

The Next Generation Energy Act of 2007 introduced, in addition to a minimum spending requirement of 1.5 percent, an energy-saving goal of 1.5 percent of gross annual retail electric energy sales by 2010. Minnesota Power has a proven track record with successful conservation program delivery, meeting or exceeding the 1.5 percent energy-saving goal in Minnesota. As shown in **Figure 5-12**, Minnesota Power has delivered at or above the 1.5 percent savings target since the goal went into effect in 2010 and delivered similar savings levels in the two years preceding the establishment of an energy-savings goal as defined in the Next Generation Energy Act of 2007.

Figure 5-12. Minnesota Power's 2004–2013 CIP Achievements



[2] Minnesota Power's Integrated Resource Plan; Docket No. E015/RP-13-53.

Minnesota Power's commercial program under its CIP delivers around 80 percent of total claimed savings. Energy savings and rebates paid under the commercial program specific to the Menahga Project area from 2005 – 2013 are provided in **Table 5-14** (the towns around the Project are Park Rapids, Menahga, Sebeka, Hubbard, Nimrod and Huntersville).

Table 5-14. Minnesota Power - CIP Projects in the Menahga Project Area

City	# of Projects	Year	kWh Saved	kW Saved	Rebate
Menahga	3	2005	16,972	8.79	$1,794
Menahga	1	2006	10,440	2.61	$522
Menahga	2	2007	40,119	17.92	$5,325
Menahga	2	2008	129,979	66.40	$14,085
Menahga	7	2009	59,555	11.90	$3,692
Menahga	2	2010	13,870	2.80	$791
Menahga	4	2011	376,235	14.60	$14,860
Menahga	4	2012	35,472	10.60	$3,554
Park Rapids	11	2005	836,562	44.22	$33,605
Park Rapids	11	2006	4,772,923	403.22	$151,100
Park Rapids	4	2007	3,309,082	204.20	$45,815
Park Rapids	25	2008	2,063,422	233.21	$98,181
Park Rapids	18	2009	2,680,867	243.52	$104,273
Park Rapids	31	2010	3,069,795	212.30	$116,910
Park Rapids	23	2011	562,757	71.40	$24,036
Park Rapids	27	2012	846,516	114.30	$51,482
Park Rapids	19	2013	2,580,550	255.60	$90,451
Sebeka	2	2006	1,050	0.37	$84
Sebeka	1	2007	3,675	1.50	$294
Sebeka	5	2008	86,568	19.40	$5,606
Sebeka	1	2010	12,791	2.20	$448
Sebeka	2	2011	8,598	3.00	$466
Sebeka	5	2012	149,537	59.10	$15,233
Sebeka	1	2013	6,759	5.20	$1,017
Total	**211**		**21,674,094**	**2008.36**	**$783,624**

5.8.3 Conclusion

The load levels shown in **Table 5-11** assume Applicants will be successful in reaching the DSM and CIP energy savings objectives in their Resource Plans. As shown in **Figure 5-11**, near-term winter peak load levels are already exceeding the capacity of the system to reliably serve all load in the affected load area without remedial actions such as switching operations to shift load off the system. For DSM or CIP to be feasible alternatives to the Project, these programs would not only need to meet their objectives, they would also have to provide additional reductions in demand to offset projected load growth in the affected load area. Based on historic DSM and CIP savings as well as forecasted load growth, it is not realistic to expect that DSM and conservation measures can achieve the level of reduction necessary within the affected load area.

5.9 Delay of the Project

Minnesota Rule 7849.0300 requires a discussion of anticipated consequences to its system, neighboring systems, and the power pool should the Project be delayed one, two, and three years, or postponed indefinitely. The 2016/17 winter peak has been designated as the in-service date for the Project; therefore, a One Year Delay translates to a 2017/18 winter date.

The inadequacies in the affected load area are thermal overloading of transformers and voltage regulators. As discussed in **Section 5.6**, the affected load area has shown growth rate in the past five years. A robust transmission system is required to address the deficiencies in the existing system and provide service to new loads that come to the affected load area.

The analysis using the historical load data shows that the loads in the affected load area have grown above the maximum load-serving capability of the transmission system. Delay of the Project worsens thermal overload concerns. Maintenance of the transmission lines would also be more difficult as the Project is delayed. As discussed in **Section 5.6** and shown in the duration curve, the number of hours that the affected load area is vulnerable to inadequacies increases. To bring the transmission system within the proper operating conditions, curtailment of loads in the affected load area is required. This would result in an unavailability of power to a significant portion of consumers in the affected load area. The critical demand analysis in **Table 5-15** summarizes the duration at which load is at risk and the magnitude of the load that needs to be curtailed to bring the system in to normal operating conditions.

Table 5-15. Critical Demand Analysis – Todd-Wadena and Minnesota Power

Scenario	2016/17 Winter Forecast	One Year Delay	Two Year Delay	Three Year Delay	Infinite Delay[2]
# Hours above Critical Demand	2699	2773	2839	2907	3134
Curtailed Demand in MW[3]	7.99	8.20	8.39	8.59	9.20
% of Local Deman3d Curtailed	41.2	41.8	42.4	43.0	44.6
Annual # of Days at Risk[1]	112	115	118	121	130

[1] Based on 2013-14 load curve
[2] Based on 2023 demand projections
[3] Curtailment assumes no remedial actions (switching)

5.10 Effect of Promotional Practices

The growth in demand in the Project service area is a result of a new industrial load (pump station) and growth in the number of customers and in the energy that each customer is consuming. Applicants have not engaged in any promotional practices to encourage the use of more power. Just the opposite, as described in **Section 5.8,** Applicants have spent significant sums of money promoting conservation and demand side management.

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