CHAPTER

2

2. Assessment of Need for Electric System Improvements

This chapter discusses the applicants' transmission planning efforts to meet the forecasted needs for the La Crosse/Winona transmission system network. The discussion includes:

- A description of the existing area transmission network system.
- Current and future loads.
- Transmission planning studies performed to identify the need and to evaluate alternatives.
- The alternatives' costs and load serving capabilities.

2.1. TRANSMISSION PLANNING CRITERIA

Electric power transmission systems are evaluated to identify existing and emerging concerns that affect their operation and reliability.

The applicants identified possible future overloads and low voltages on the transmission system under normal, first contingency, and multiple contingency conditions in the La Crosse/Winona (Project) area. The applicants performed contingency analyses in accordance with North American Electric Reliability Corporation (NERC) standards and using its planning criteria. These analyses examined the performance of the transmission system when a single element or a combination of multiple elements of the transmission system suddenly failed. The applicants followed the following NERC planning standards:

a. No system element (line, transformer, terminal equipment, etc.) should experience loading in excess of its normal rating for NERC Category A (normal) conditions; that is, with all transmission facilities in service.
b. No voltage levels that cause damage to the applicants' or their customers' facilities should be allowed on a sustained basis. The acceptable voltage range is 95 to 105 percent of nominal voltage for NERC Category A conditions.
c. No transmission element should experience loading in excess of its applicable emergency rating for applicable Category B (loss of single element) contingencies. In planning studies, load shedding may not be utilized for immediate overload relief.
d. Under applicable NERC Category B contingencies, the temporary acceptable voltage range is 90 to 110 percent of the system nominal voltage. In planning studies, load shedding may not be utilized for immediate voltage restoration.
e. Generation real power output should not be limited under NERC Category B contingency conditions.
f. No transmission element should experience loading in excess of its applicable rating for applicable NERC Category C (multiple element outage) contingencies. Overload relief methods may include minimal planned and controlled load shedding.

2.2. AREA OF INTEREST

The La Crosse/Winona area includes La Crosse, Onalaska, and Holmen, Sparta, Arcadia, Trempealeau, Buffalo City, Cochrane, and the surrounding rural areas in Wisconsin and Winona/Goodview, La Crescent, Houston, and Caledonia in Minnesota. The area can be seen in the map of the existing electric transmission system in Figure Vol. 2-2. The area is served by Xcel and DPC members Vernon Electric Cooperative, Tri-County Electric Cooperative, Oakdale Electric Cooperative, and Riverland Energy Cooperative (Riverland).

2.3. EXISTING LA CROSSE/WINONA AREA ELECTRIC TRANSMISSION SYSTEM

The La Crosse/Winona area is mainly served by a network of 161 kV and 69 kV transmission lines. The La Crosse/Winona area and the four primary transmission 161 kV links or sources of power areas are shown in Figure Vol. 2-2. These four 161 kV transmission lines are Alma-Marshland-La Crosse Tap, Alma-Tremval-La Crosse, Genoa-Coulee, and Genoa-La Crosse Tap[13].

The applicants state that the growing demand for electricity in the La Crosse/Winona area would exceed the capabilities of the existing electrical system to deliver power reliably under contingency conditions, when one or more than one elements of the electrical system was out of service.

2.4. EXISTING ELECTRIC GENERATION

The transmission system's ability to serve the La Crosse/Winona area reliably depends on the operating status of local major power plants. The power plants and their capacities, fuel types, and distances from La Crosse are shown in Table 2.4-1.

Table 2.4-1 Power plants serving the La Crosse/Winona area

Plant	Capacity (MW)	Fuel Type	Distance from La Crosse (miles)
John P. Madgett	395	Coal	40
Alma Units 1-5	208	Coal	40
Genoa Unit 3	377	Coal	20
French Island Units 1 and 2	26	Refuse	Within the city of La Crosse
French Island Unit 4	70	Oil	Within the city of La Crosse
French Island Unit 3	70	Oil	Currently not operational

French Island Unit 3, which had a 70 MW capacity, is currently not operational.

2.5. AREA LOAD FORECAST

One of the stated reasons for this new line is to address the community load serving needs in the La Crosse/Winona area. The analysis of need conducted by the PSCW has been limited to the La Crosse/Winona area. In addition to the Winona area in Minnesota, the areas in Wisconsin served by this line are Buffalo, Trempealeau, and La Crosse Counties, including the communities of Alma, Buffalo City, Fountain City, Arcadia, Galesville, Trempealeau, Holmen, Onalaska, La Crosse, and the surrounding rural areas.

[13] The La Crosse-Monroe County 161 kV line does not provide a meaningful source to the greater La Crosse area because it is the strongest source for Sparta and Tomah, given the relatively weak transmission source from the east.

The analysis of need for this line in the CPCN application begins with the statement that the La Crosse/Winona area "is facing reliability issues as a result of population growth and the resulting increase in demand for electricity."[14] It is not clear to PSCW staff that there will be sufficient population growth in the La Crosse/Winona area to justify the projected increase in demand for electricity presented in the CPCN application.

Peak load growth in the La Crosse/Winona area from 2002 to 2010 was 6.2 percent[15] or an average annual growth rate of 0.77 percent. Population growth during this same time period was 4.3 percent[16] or an average annual growth rate of 0.54 percent. The population in the La Crosse/Winona area is projected to increase at an average annual rate of 0.49 percent from 2010 to 2030.[17] However, the applicants have projected the average annual growth in peak load over the same time period to be 1.7 percent.[18] This projected peak load growth rate is more than twice the historical peak load growth rate even though the projected population growth rate is lower than the historical population growth rate.

The changes in peak load for the years 2002 to 2010 appear to be weather related. Table 2.5-1 shows annual peak temperatures and annual peak loads from the years 2002 through 2010. Figure 2.5-1 illustrates the relationship between peak day load and temperature for the La Crosse area. The graph in the figure shows that peak load correlates closely with peak temperature. The 6 percent decrease in peak load for 2004 appears to be due to a very low peak temperature, and the 9 percent increase in peak load for 2006 appears to be due to a very high peak temperature. However, after 2006 the fall in load is not as precipitous as the fall in temperature.

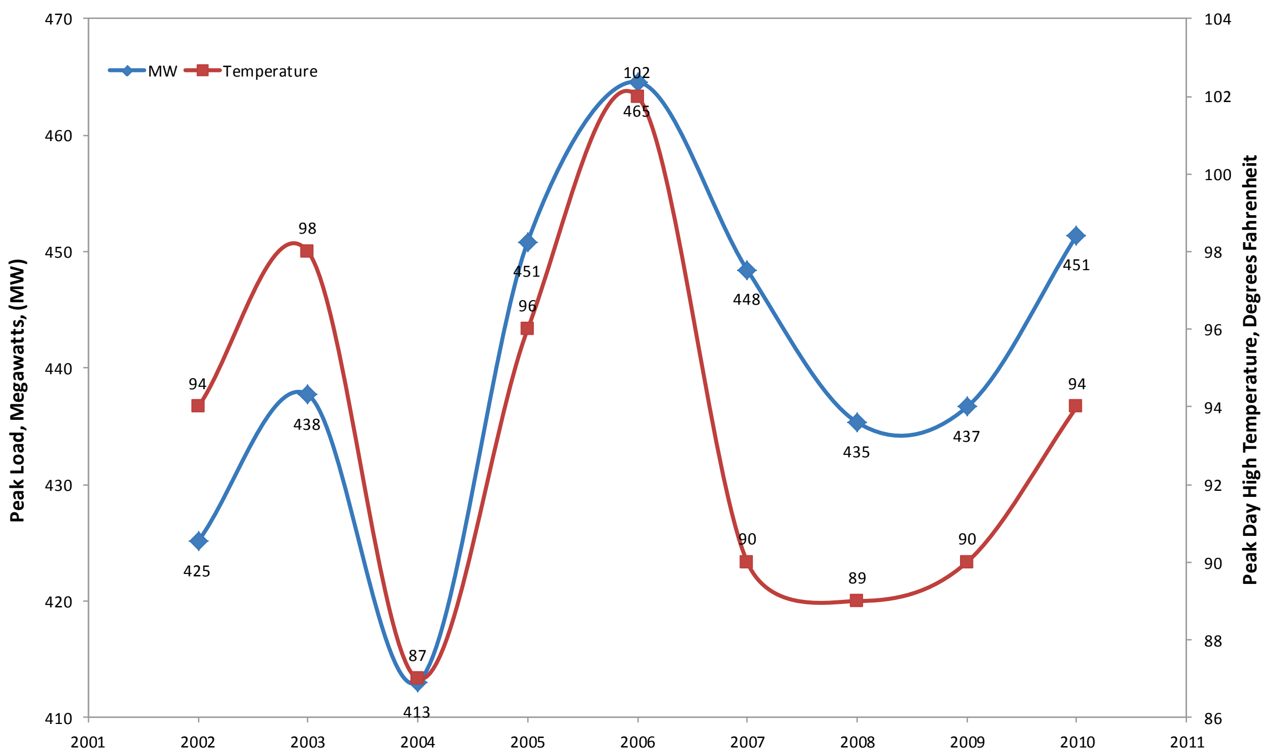
Some of this increase in electricity demand may be due to both the increased population over time and the economic recovery in the area. Percentage growth in employment from 2009 to 2010 for La Crosse County was 0.7 percent. [19] The country as a whole also experienced an increase in electricity consumption due to the economic recovery and weather with warmer summer temperatures and colder winter temperatures in 2010 as compared to 2009.[20] However, current economic data indicate very weak economic recovery so the projected annual percentage peak load growth rate of 1.7 percent used in the CPCN application is high.

[14] CapX2020 CPCN Application, Appendix E, p. 13.
[15] Dairyland Power Cooperative, Xcel Energy.
[16] Time Series of The Final Official Population Estimates and Census Counts for Wisconsin Counties, Prepared by Demographic Services Center, Wisconsin Department of Administration. County Population Estimates 2000-2010 - Time Series of The Final Official Population Estimates and Census Counts for Wisconsin Minor Civil Divisions, Demographic Services Center, Wisconsin Department of Administration. Annual estimates of city and township population, households and persons per household, 2000-2009, Minnesota State Demographic Center and the Metropolitan Council, July 30, 2010. Population change for Minnesota's largest cities, 2000-2010, Minnesota Department of Administration, Geographic and Demographic Analysis Division, March 17, 2011.
[17] County Population Projections Wisconsin, Demographic Services Center, Wisconsin Department of Administration, October 2008. MCD and Municipal Population Projections, 2005-2030, Demographic Services Center, Wisconsin Department of Administration, May 30, 2008. Minnesota Minor Civil Division Extrapolated Population Minnesota State Demographic Center, October 2007.
[18] Dairyland Power Cooperative, Xcel Energy.
[19] Bureau of Labor Statistics, Quarterly Census of Employment and Wages.
[20] Federal Energy Regulatory Agency, "2010 State of the Markets," April 21, 2011.

Table 2.5-1 Peak temperature and peak load

Year	Peak Temperature	Peak Load (MW)
2002	94	425.13
2003	98	437.71
2004	87	413.04
2005	96	450.84
2006	102	464.58
2007	90	448.43
2008	89	435.35
2009	90	436.66
2010	94	451.41

Figure 2.5-1 Peak load and temperature



To understand the timing of the La Crosse/Winona area need, planning engineers from DPC and Xcel developed a peak load forecast for substations operating in the affected La Crosse/Winona areas. They gathered eight years of historical data and estimated projected peak load growth. For substations served by the DPC distribution cooperatives, the forecast was estimated by first calculating an average load for years 2004 to 2009 for each substation. To create a forecast to the year 2020, planning engineers then applied a growth rate based on the historical peak growth rates of the distribution cooperatives.
The 2010-2020 forecast for the Xcel substations was based on an analysis of historical loads and anticipated growth rates. Xcel used the peak demand for 2006 and grew that load in their model by 1.2 percent through the year 2020. However, 2006 had the highest temperature at peak load over the time period 2002-2010. The combination of these two estimation methods resulted in an annual percentage growth for the time period 2010 to 2050 of 1.9 percent. This projection seems high since the actual annual percentage peak load growth over the time period of 2002 to2010 has been 0.77 percent.

For transmission planning purposes, Midwest Independent Transmission System Operator, Inc. (MISO) has established effective growth rates under four future scenarios. Scenario 1, receiving 51 percent of stakeholder support as the most likely scenario, has an effective growth rate of 0.78 percent. This scenario assumes that existing energy policies are maintained with low demand and energy growth rates representing the continuation of the economic downturn. MISO Scenario 2, receiving 15 percent of stakeholder support, has the highest effective growth rate at 1.28 percent. Scenario 2 assumes existing energy policies are maintained with a return to quick recovery from the economic downturn. Scenario 3, receiving 16 percent of stakeholder support, captures a list of future energy policies including a 20 percent RPS, a carbon cap, smart grid, and electric vehicles. Scenario 4, receiving 19 percent of stakeholder support, models a declining cap on future carbon emissions. Scenarios 3 and 4 have the lowest effective growth rates at 0.52 percent and 0.03 percent, respectively.

Table 2.5-2 shows a comparison of the peak loads using the applicants' forecasted growth rate with the most likely MISO Scenario and the highest growth rate MISO Scenario. Given the growing consensus that economic recovery will be slow, the heavy support for Scenario 1 by MISO stakeholders and the population forecasts for the La Crosse/Winona area, the lower MISO forecast shown in Table 2.5-2 is deemed most likely.

Table 2.5-2 Comparison of peak load projections (in MW)

Year	Applicants' Rate of 1.70%	MISO Rate of 0.78%	MISO Rate of 1.28%
2015	514.98	469.29	481.05
2020	547.57	487.88	512.63
2025	583	507.21	546.29
2030	620	527.30	582.16

2.6. ASSESSMENT OF AREA TRANSMISSION RELIABILITY

The transmission system normal operation requires that an outage of a single transmission element or equipment component (transformer, transmission line, or generator) should not imperil the transmission system. This operating mode is called the N-1 criterion—the ability of the transmission system to sustain operation with the failing of one element. The sudden unplanned failure of a transmission system element is called a contingency event. NERC Operating System Guidelines require that an area transmission system should be capable of successful operation in the event of failure of two elements of the transmission system. Such a failure of two elements is called an N-2 contingency.

2.6.1. N-1 contingency

The applicants identified an N-1 critical contingency that limited load serving capability to 460 MW with the operation of all generating units at Alma and Genoa. With additions of two 60 megavolt amperes reactive (MVAR) capacitor banks to the La Crosse area 161 kV system, the load serving capability increased by 10 MW to 470 MW. With operation of the 70 MW peaking French Island Peaking Unit 4 generation, the load serving capability could be increased to about 540 MW.

Commission staff considers that reactivating the French Island Unit 3 generator could further increase the load serving capability to 610 MW.

2.6.2. N-2 contingency

The applicants identified an N-2 critical contingency that limited load serving capability up to 430 MW[21] . The applicants consider that additional electrical infrastructure is needed to provide load serving capability for customer loads greater than 430 MW.

Commission staff considers that operation of French Island Unit 4 could increase the load serving capability to 500 MW and that reactivating French Island Unit 3 could increase it to 570 MW.

[21] See Data Response PSCW REF #154647, p. 2.