CHAPTER

3

3. Potential System Solutions

3.1. NO BUILD OPTION

The applicants' analysis shows that, if nothing is done, load-serving capability in the area will be limited to 610 MW in the event of a critical N-1 Contingency and limited to 460 MW in the event of a critical N-2 contingency. These load-serving limits would be achieved with the operation of the French Island Unit 4 generator and currently mothballed French Island Unit 3.

3.2. NON-TRANSMISSION OPTIONS

3.2.1. Request for more options

In March 2011, Commission staff requested an analysis of non-transmission alternatives to address the needs in the La Crosse service area. These included hypothetical generation solutions and programs to reduce the demand for electricity (via DSM, energy efficiency, or load management). The applicants responded, and their response is summarized in this section.[22]

In Table 2.5-2 in Section 2.5 of the draft EIS, the MISO peak load projection for the area in 2020 with 0.78 percent growth is shown to be 487.88 MW. In Section 3.1, it is noted that if the proposed project is not built, the load-serving capacity of the existing transmission system would be limited to 460 MW in the event of a critical N-2 contingency. Such load serving limits would be achieved with generation from the French Island Unit 4 generator and the currently mothballed French Island Unit 3 generator. The applicants state that transmission grid reliability would require the demand/supply ratio to stay level until 2020, with a reduction of 98 MW of demand or an increase of 98 MW of generation in the La Crosse area needed over that time. This section will discuss whether other non-transmission options could meet the area's projected need.

The applicants have already concluded that neither additional generation nor DSM would satisfy their stated need for local service reliability, generation support, and regional reliability. Energy efficiency and load management do not provide region-wide benefits, and additional local generation would not provide region-wide benefit without the addition of transmission. These alternatives also would not supply the additional connections that a 345 kV line would offer that would "provide for a more robust system that will be better able to withstand system contingencies." The applicants also state that neither DSM nor the addition of local generation itself can provide "foundation bulk transmission facilities across the

[22] PSCW REF #146720.

Minnesota/Wisconsin border to enable future power transfers into Wisconsin" to support generation development elsewhere.[23]

Current generation resources to meet the needs of the area appear adequate. Projected reserve margins and the need for economical energy typically drive investment decisions for generation. In addition, the installation of any large generation typically requires an increase in transmission capacity to move the power from the source. It would be necessary to assess those additional needs if generation were to be added.

3.2.2. Load reduction as an option

The applicants state that implementation of load reduction programs as an alternative would require that load management programs be monitored continuously to make sure that load levels do not increase to the point where they cause problems for the transmission system. This is because these programs rely on voluntary compliance. Such monitoring would likely also be appropriate if energy efficiency were part of the alternative solution, because participation in energy efficiency programs is also voluntary.

The applicants maintain that the 98 MW needed in the La Crosse area cannot be met by DSM programs. The July 2009 "Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin" study conducted by the Energy Center of Wisconsin (ECW) suggests that peak demand can cost effectively be reduced by 1.6 percent annually on a statewide basis, after a ramp-up period. If this level of reduction could be achieved in the La Crosse area, peak demand growth could be negative. However, at this time, there is no regulatory authority to ensure energy user compliance with load reduction and energy efficiency goals. The effort would need to rely on voluntary compliance, and no mechanism has been identified that would ensure adequate participation over time. Because of the nature of human and economic activity, there would be no guarantee that a one-time measure in the area would have a lasting effect.

Cost would also be an issue, or at least an unknown. ECW evaluated energy efficiency on a Total Resource Cost (TRC) basis. Although the TRC test includes program costs, it does not include incentive payments, as these are simply transfer payments. Cost-effectiveness of energy efficiency and load management from the applicants' perspective would require identification of the programs to be used to capture the peak demand savings and the entities responsible for implementing and administering those programs.

3.2.3. Generation options with renewable resources or natural gas

On request, the applicants evaluated several generation alternatives to address load needs in the project area from 2015 through 2020. These included wind power, solar power, and biomass-fired, landfill gas-fired, and natural gas-fired options. They are summarized here.

3.2.3.1. Wind power

At this time, the capacity of a typical wind turbine ranges from 1.5 to 2.0 MW. However, wind power is a variable resource that is dependent on the availability of wind to operate, and a wind project's capacity factor in the Midwest would range from approximately 20 to 40 percent of its nameplate capacity depending on the location.[24] Because it is dependent on the availability of wind, wind generation is not dispatchable and cannot be brought online quickly during the day to respond to changes in area electricity

[23] PSC REF #146720, p. 1.
[24] Capacity factor is a comparison of a turbine's actual power production over a year with the amount of power that it would have produced if it had run at full capacity over that time.

use. Over a year, peak electrical demand periods occur in the summer, but peak generation by wind turbines generally occurs during the windier seasons of fall, winter, and spring. Even during the peak summer months, it is generally windier during off-peak hours than during peak hours.

As an alternative for purposes of meeting electricity load needs, wind generation would require either storage or an additional source of generation that is dispatchable and can fill the need when wind power supply is inadequate.

To provide the 98MW of capacity needed in the La Crosse service area in 2020, at the more efficient 40 percent capacity factor, about 163 1.5 MW wind turbines would be needed with an overall capacity of 245 MW. If the National Renewable Energy Laboratory (NREL) unit spacings per MW of wind power are used, 60 acres are needed to site 1 MW of wind. This would translate to about 14,700 acres (about 23 square miles) of land needed for the appropriate number of 1.5 MW wind turbines. In addition to the wind turbines themselves, transformers, collection power lines, a substation, connecting transmission line(s), and access roads would be needed. The turbines, transformers, access roads, and substation land would need to be purchased, and ROW easements would need to be purchased for power lines. Negotiations for these purchases would take time. In addition, since any generation project over 100 MW would require a CPCN from the Commission, there would be the need for another review process with hearings. CPCN processes could take up to a year or more.

A wind project would have a capital cost of approximately $2.2 million per MW of installed capacity. Unlike several other alternatives, there would be no fuel cost associated with a wind project. However, based on a 40 percent capacity factor as described above, the 245 MW of wind capacity needed to serve the electric demand would cost approximately $539 million.

If wind power was to be imported from outside the La Crosse service area, that power would likely require additional transmission line facilities to be built from the source to the service area. The voltage of the transmission lines might not need to be as high as the line proposed, but that would need to be evaluated.

3.2.3.2. Solar power

Unlike wind power, photovoltaic resources for solar power have the benefit of providing peak electrical generation during hot, summer days, which coincides with part of the period of peak demand. However, peak load often extends into summer nights as well, when photovoltaic systems stop generating electricity. Without sufficient storage capacity, this problem limits their usefulness in resolving the identified electrical deficiencies.

At this time, there are no existing photovoltaic facilities that are large enough to be considered in transmission studies or dispatched to the MISO market in the project area. Siting and construction of new photovoltaic facilities would take time, possibly including the time required for a Wisconsin CPCN review if one or two large facilities were located on the Wisconsin side of the Mississippi River. Several solar photovoltaic technologies could be employed, at varying levels of cost and efficiency. Crystalline solar cells are more efficient at converting sunlight into electricity, and could cost $2.50 to $6 per (direct current (DC)) watt or less. Thin film solar cells are less efficient, but would also cost less than crystalline cells.[25] Thin film solar systems would provide approximately 5 watts (DC) per square foot, whereas the more efficient crystalline solar systems would provide between 8 to 19 watts (DC) per square foot depending on the precise technology used. Applying a 0.80 derate factor and assuming a 20 percent capacity factor, a

[25] Market prices of solar cells are difficult to determine and may be lower than described here; the Commission has not reviewed any proposals for large solar systems that could be used for comparison.

system using the most efficient crystalline cells would need to be approximately 612.5 MW in size to provide 98 MW of capacity, and would require about 1.156 square miles to install.[26]

As with wind power, physical obstructions and local laws might increase the area needed for this capacity. Depending on where it was located, additional transmission line facilities might also be required.

3.2.3.3. Biomass power

As with the other renewable technologies, additional facilities would have to be constructed to meet the 98 MW minimum additional capacity required to ensure area transmission grid reliability through 2020.

Based on data the applicants have received from vendors, it appears that more than one biomass-fired generation plant would be needed. The vendors, Barr Engineering Company and Cook Engineering, produced a marketing brochure called "Mulch to Megawatts" that indicates that, with a typical biomass supply for a new power plant site, 25 MW is an optimal size for a project in terms of capital costs and fuel supply costs.[27] Smaller projects would be more expensive, relatively, and larger projects would likely require larger fuel acquirement radii. Three such biomass plants would not generate 98 MW, even if they could accomplish a 100 percent capacity factor. The vendors estimate the optimum cost and size of a plant to be about $3,335 per kW for a 25 MW plant, including costs for environmental protection. At less than 25 MW, the capital cost per kW increases and, at greater than 25 MW, the fuel supply costs increase.[28] The Commission recently approved a 50 MW biomass-fired cogeneration plant at a cost of about $255 million.[29] This cost is greater than the anticipated cost of the CapX Alma-Holmen project, and it provides only 50 MW of capacity.

3.2.3.4. Landfill gas

There is not sufficient available landfill gas in the La Crosse area to meet the minimum additional capacity needed to ensure transmission grid reliability. Existing landfills are small units, not likely to trigger a need for new transmission assets on their own, and they are not a technically feasible non-transmission alternative.

3.2.3.5. Natural gas

To evaluate natural gas-fired generation as an alternative for service area reliability, the applicants assessed the amount of such generation needed to meet the 98 MW transmission deficiency and the estimated costs of that generation.

The addition of natural gas-fired generation as a fast-response peaker would increase the reliability of serving load in a relatively small geographical area if high capacity transmission lines are not built. Thus, to avoid high-voltage transmission construction throughout the area, the applicants state that small generators would have to be added in specific load centers. The more small generators that must be built, however, the greater the cost per MW for the benefit received.[30]

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[26] The following numbers can be used to find the approximate system size that can be placed in a given space.
- Crystalline PV System: 8-11watts/square foot
- Thin Film PV System: 5 watts/square foot
- HE Crystalline System: 17-18 watts/square foot

http://www.nrel.gov/docs/fy10osti/46078.pdf. December 2009.

[27] PSCW REF #146720, Attachment 1.

[28] PSCW REF #146720, Attachment 1, p. 2.

[29] PSCW REF #148090, Final Decision, Wisconsin Electric Power Company Rothschild Biomass Cogeneration Project.

[30] PSCW REF #146720, p. 4.

To meet the La Crosse area need for additional transmission grid line capacity, it appears that at least 100 MW of natural gas capacity would be needed. The capital cost of one 100-MW natural gas-fired plant would likely be close to $100 million, around half the expected cost of the proposed transmission project. However, in addition to the capital cost, there would be the costs of fuel and maintenance, larger natural gas supply lines, and improved transmission connections if the existing lines near the new plants do not have the capacity. Thus the installation cost appears relatively high, and potential environmental impacts would remain to be assessed.

The applicants suggest doubling the generation capacity needed so that the right amount is available when needed. However, based on the capacity factors or run time of existing peakers at French Island, small plants would seldom run, making them uneconomical. Without a need for replacement or additional generation, natural gas capacity would not be profitable and any new local generation would not meet criteria of reasonable need for PSCW approval.

3.3. TRANSMISSION ALTERNATIVES—DESCRIPTIONS

The applicants developed their peak load forecast for the La Crosse/Winona area which shows a peak load of about 515 MW in 2015 and 548 MW in 2020.[31] Commission staff's forecast for the La Crosse/Winona area, discussed above in Section 2.5 , shows a peak load of about 469 MW in 2015 and 488 MW in 2020.

The applicants evaluated several transmission system options or alternatives to serve the needs of the La Crosse/Winona area. The alternatives, their load serving capabilities, and costs are described below.

3.3.1. Alma-La Crosse 345 kV transmission line option (proposed project)

In its CPCN-application discussion of long-term electric transmission planning considerations, the applicants state that the La Crosse/Winona area load-serving requirements "justified" the proposed 345 kV transmission line project "even if no future 345 kV or higher transmission projects are constructed."[32]

The proposed project would serve the La Crosse/Winona area load up to 750 MW, and up to 890 MW with the operation of French Island Unit 4 and reactivation and operation of French Island Unit 3 as discussed above in Section 2.6 of Chapter 2.

However, the applicants also emphasize that the proposed project would prove pivotal for future expansion of the regional 345 kV transmission network for providing generation interconnections and increasing Minnesota-to-Wisconsin power transfers. The applicants state that the *Strategic Midwest Area Renewable Transmissions Study* (SMART),[33] the *Green Power Express* plans, the interregional *Joint Coordinated System Plan* (JCSP), and the *Regional Generation Outlet Study* (RGOS) released by MISO in November 2010,

[31] See CPCN Application, Table 2.1-10, pp. 2-39-2-40.
[32] See CPCN Application, pp. 1-19.
[33] The SMART Study was developed by Electric Transmission America (a transmission joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Company), American Transmission Company, Exelon Corporation, Northwestern Energy, MidAmerican Energy Company (a subsidiary of MidAmerican Energy Holdings Company), and Xcel Energy.

all indicate that a Hampton-Rochester-La Crosse 345 KV transmission line would be an important underlying facility.[34]

3.3.2. Reconductor option

A transmission alternative was examined that focused on reconductoring and rebuilding existing lines. This reconductor alternative would require the transmission line upgrades, new transformers, and substation expansions shown in Table 3.3-1. In addition to the transmission upgrades, some 161 kV and 69 kV lines would require clearance and terminal upgrading. The reconductor alternative would reliably serve La Crosse/Winona load up to 600 MW and up to 740 MW with the operation of French Island Unit 4 and reactivation and operation of French Island Unit 3.

Table 3.3-1 La Crosse area reconductor alternative[35]

161 kV Line Rebuilds	Miles
Genoa - La Crosse Tap	21
Coulee - La Crosse	8.5
Genoa - Coulee	19
Genoa - Lansing	20
Alma - Marshland	27
La Crosse - Mayfair	4
Marshland - La Crosse Tap	24
Total Miles of Rebuilt 161 kV	123.5

69 kV Line Rebuilds	Miles
Coulee - Swift Creek	2
Coulee - Mt. La Crosse	5
Total Miles of Rebuilt 69 kV	7

New 161/69 kV Transformers	Size
Tremval Upgrade existing	112 MVA
Coulee #3	112 MVA
Marshland #3	112 MVA
La Crosse #1	112 MVA
La Crosse #2	112 MVA
Coulee #1	112 MVA
Monroe County #2	70 MVA

Substations (New and Expansions)	
Coulee	Expansion
Marshland	Expansion

3.3.3. 161 kV Red Wing-La Crosse transmission line option

This transmission alternative includes a new 161 kV line about 101 miles long from Red Wing, Minnesota, to La Crosse, Wisconsin, with connecting ties to the Spring Creek, Lake City, Alma, Marshland, Onalaska, and La Crosse Substations as well as the upgrades shown in Table 3.3-1. The total upgrades and new 161 kV line for the alternative are shown in Table 3.3-2. The 161 kV Red Wing-La Crosse transmission line alternative would serve the load growth in the La Crosse/Winona area up to about 750 MW, and up to 890 MW with the operation of French Island Unit 4 and reactivation and operation of French Island Unit 3.

[34] See CPCN Application, pp. 1-19 and 2-30 and Supplemental Need Study (August 2011), pp. 55-58.
[35] See CPCN Application, Appendix E, pp. 26-27.

Table 3.3-2 161 kV Red Wing-La Crosse transmission line alternative[36]

161 kV Line Rebuilds	Miles
Genoa-La Crosse Tap	21
Coulee-La Crosse	8.5
Genoa-Coulee	19
Genoa-Lansing	20
Alma-Marshland	27
La Crosse-Mayfair	4
Marshland-La Crosse Tap	24
Total Miles of Rebuilt 161 kV	125.5
69 kV Line Rebuilds	**Miles**
Coulee-Swift Creek	2
Coulee-Mt. La Crosse	5
Total Miles of Rebuilt 69 kV	7
New 161 kV Lines	**Miles**
Alma-Marshland #2	28
Marshland-Onalaska	26
Onalaska-La Crosse	5
Spring Creek-Lake City	20
Lake City-Alma	22
Total Miles of New 161 kV	101

New 161/69 kV Transformers	Size
Tremval Upgrade Existing	112 MVA
Coulee #3	112 MVA
Marshland #3	112 MVA
La Crosse #1	112 MVA
La Crosse #2	112 MVA
Coulee #1	112 MVA
Monroe County #2	70 MVA
Jackson Co. Upgrade Existing	112 MVA
Lake City #2	70 MVA
Onalaska #1 and #2	112 MVA

Substations (New and Expansions)	
Coulee	Expansion
Marshland	Expansion
Alma	New
Spring Creek	Expansion
Onalaska	New
Lake City	Expansion

3.3.4. Single-circuit 1613.3.4. Single-circuit 161 kV North Rochester-La Crosse transmission line option[37]

This alternative includes a new 161 kV transmission line between the North Rochester 161 kV Substation and a new Briggs Road 161 kV substation. The alternative would serve load in the La Crosse/Winona area up to 550 MW, and up to 890 MW with the operation of French Island Unit 4 and reactivation and operation of French Island Unit 3.

3.3.5. Double-circuit 161 kV North Rochester-La Crosse transmission line option[38]

This alternative includes a double-circuit 161 kV transmission line between the North Rochester and Briggs Road 161 kV substations. The alternative would serve load in the La Crosse/Winona area up to 600 MW, and up to 740 MW with the operation of French Island Unit 4 and reactivation and operation of French Island Unit 3.

3.3.6. Single-circuit 230 kV North Rochester-La Crosse transmission line option[39]

This alternative includes a single-circuit 230 kV transmission line between the North Rochester and Briggs Road substations. The alternative would serve load in the La Crosse/Winona area up to 550 MW, and up to 690 MW with the operation of French Island Unit 4 and reactivation and operation of French Island Unit 3.

[36] CPCN Application, Appendix E, p. 27.
[37] CPCN Application, Appendix E, p. 28.
[38] CPCN Application, Appendix E, pp. 28-29.
[39] CPCN Application, Appendix E, p. 29.

3.4. TRANSMISSION ALTERNATIVES—COST AND PERFORMANCE COMPARISON

The above transmission alternatives are compared in Table 3.4-1 below. The costs included in the table are planning-level costs used primarily for comparison purposes. The project costs of the proposed 345 kV project could be further reduced because it may receive cost benefits from MISO members if it is recognized by MISO as a Baseline Reliability Project.[40]

The proposed 345 kV project would not increase by itself the transfer capability from Minnesota to Wisconsin. However, it would provide a critical structural link to the transmission system to expand the system from La Crosse east by a high voltage transmission line to support the transfer capability up to 1,200 MW.[41]

Table 3.4-1 Cost and performance comparison of transmission line alternatives based on 2010 dollar planning level estimates[42]

Alternatives	La Crosse/Winona Area Load Serving Capability (MW)	Project Cost ($ million)	Transmission Losses Cost ($ million)	Total Cost ($ million)*
345 kV Proposed Project	750 MW	201	0	201
Reconductor Option	600 MW	182	36	218
Transmission Line Option: 161 kV Red Wing-La Crosse	750 MW	332	3	335
Transmission Line Option: Single-Circuit 161 kV North Rochester-La Crosse	550 MW	70	32	102
Transmission Line Option: Double-Circuit 161 kV North Rochester-La Crosse	600 MW	95	23	118
Transmission Line Option: Single-Circuit 230 kV North Rochester-La Crosse	550 MW	83	18	101

* For this comparison, Total Cost = Project Cost + Transmission Losses Cost

Each load serving capability shown in Table 3.4-1 can be further increased by 70 MW by utilizing the operation of French Island Unit 4. It could be further increased by 140 MW by utilizing the operation of French Island Unit 4 and reactivation and operation of French Island Unit 3 as discussed above in Section 2.6.

3.5. SCENARIOS FOR THE EXISTING DAIRYLAND POWER COOPERATIVE 161 KV LINE

The existing DPC 161 kV line, called the Q1 line, is nearing the end of its useful life but is still needed. DPC has determined that it must be either rebuild or replace the line. The line runs from Alma through Holmen and La Crosse to Genoa. The proposed project discussed in Section 3.3.1 would replace the portion from Alma to Holmen if certain routing alternatives were selected and force a different scenario for that area if others were selected.

[40] See CPCN Application, Section 2.1.9, pp. 2-65.
[41] See Supplemental Need Study, August 2011, PSCW REF #152526, p. 58.
[42] See Supplemental Need Study, August 2011, pp. 52-53.

DPC plans to reconstruct, by 2013, sections of Q1 that are not replaced by the project in this docket. Different DPC Q1 rebuild scenarios that would result from different Commission routing decisions for this project are shown in Table 12.4-1 in Chapter 12 of the draft EIS. The rebuild could require a separate CPCN from the Commission depending on how much of that line would be relocated from its existing route.

Regardless of scenario, the Q1 rebuild would create certain types of impacts beyond those anticipated for this project. Costs would be regulated by RUS. The assumed ROW width would be 100 feet. DPC envisions four routing possibilities for getting past the Black River floodplain, which lies between Alma and Holmen on the existing Q1 path. Three of those options go through the floodplain and one would cross the river at a more narrow point upstream. The four routing possibilities being considered by DPC are:

- The existing Q1 alignment;
- A route along STH 35;
- A route adjacent to the existing 69 kV line adjacent to the Seven Bridges Trail;
- A route along STH 54 south of Galesville and north of the floodplain.

Details about potential environmental impacts to the Black River and its associated wetlands and forests can be found in Chapter 7. A summary of the potential scenarios for the Q1 rebuild depending on the outcome of this docket can be found in Chapter 12, Section 12.4.