STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF GREAT RIVER ENERGY, NORTHERN STATES POWER COMPANY (D/B/A XCEL ENERGY) AND OTHERS FOR CERTIFICATES OF NEED FOR THREE 345 KV TRANSMISSION LINES WITH ASSOCIATED SYSTEM CONNECTIONS

PUC DOCKET NO. E002/CN-06-1115
OAH DOCKET NO. 15-2500-19350-2

APPLICANTS' POST-HEARING BRIEF ON THE MERITS OF THE APPLICATION FOR CERTIFICATES OF NEED

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I. INTRODUCTION

Northern States Power Company, a Minnesota corporation ("Xcel Energy"), on behalf of itself and Great River Energy, a Minnesota Cooperative Corporation ("Great River Energy") (collectively, "Applicants"), respectfully submit this Post-Hearing Brief ("Brief") to the Administrative Law Judge ("ALJ"). This Brief and the Proposed Findings of Fact, Conclusions of Law and Recommendation ("Proposed Findings") support granting Certificates of Need for the Twin Cities – La Crosse 345 kV line and associated connections ("La Crosse Project"); the Twin Cities – Fargo 345 kV line and associated connections ("Fargo Project"); and the Twin Cities – Brookings County 345 kV line and associated connections ("Brookings Project") (collectively, the "345 kV Projects").

After a lengthy proceeding (including 10 environmental scoping meetings; 19 public hearings; over 100 public hearing exhibits; over 220 written public comments; 25 evidentiary hearing days; over 300 exhibits; 50 prefiled testimonies; and hundreds of transcript pages), Applicants have satisfied their burden of proving that the 345 kV Projects are needed. The record establishes multiple needs and no viable alternatives. The Certificates of Need should not be burdened with conditions dictating the type and amount of generation that may use the facilities. And the Certificates of Need should be issued to Applicants on behalf of themselves and the other utilities who are involved in the CapX2020 initiative ("CapX2020").[1] This will facilitate the coordinated transmission planning approach established by this case.

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[1] The critical inquiry in this case is the "need" for the facility, not who owns it. Given the nature of the projects and the record of this proceeding, Applicants respectfully request that the Certificates of Need explicitly recognize that final ownership of the proposed facilities will be determined, pursuant to contract, after completion of the development phase, including after all major permits have been issued. Consistent with the recommendation of the Minnesota Department of Commerce, Office of Energy Security ("OES"), Applicants propose to make a compliance filing specifying final ownership after all major permits are obtained. Ex. 282 at 4-5 (Rakow Direct); Ex. 132 at 34 (Alders Rebuttal); Ex. 1 at 1.24 (Application); Ex. 2 at Apx. B-1 to B-4 (Application).

Applicants and the other CapX2020 utilities[2] want to thank all stakeholders for participating in this important regulatory process, particularly those who participated in the public meetings and hearings that provided important stakeholder feedback. (See Ex. 31 (Carlsgaard Direct)). Vigorous and diverse public participation helped inform the planning process and provided valuable feedback in developing and presenting the proposals. And the active participation of numerous and diverse interests[3] in this contested case materially aided in developing a thorough record for the ALJ and the Minnesota Public Utilities Commission ("Commission").

This Brief and the Proposed Findings summarize Applicants' proposal, the applicable law and record and shows that Applicants satisfied all requirements for Certificates of Need for the "Upsizing Alternative"[4] for the projects.[5] Applicants respectfully request that the ALJ: (i) find that Applicants have satisfied their burden of proof regarding the need for all of the 345 kV Projects, (ii) conclude that materially substantive conditions are not necessary or appropriate, and (iii) recommend that the

[2] Utilities who are currently participating in the CapX2020 initiative in some manner include: 1) Central Minnesota Municipal Power Agency ("CMMPA"), 2) Dairyland Power Cooperative ("Dairyland"), 3) Great River Energy, 4) Minnesota Power, 5) Minnkota Power Cooperative ("Minnkota"), 6) Missouri River Energy Services ("MRES"), 7) Otter Tail Power Company ("Otter Tail"), 8) Rochester Public Utilities ("RPU"), 9) Southern Minnesota Municipal Power Agency ("SMMPA"), 10) Wisconsin Public Power, Inc. ("WPPI"), and 11) Xcel Energy. Ex. 64 at 12 (McCarten Direct); Ex. 1 at 1.24-1.25 (Application).

[3] Parties to the contested case included: (i) Applicants; (ii) OES; (iii) environmental organizations represented by the Minnesota Center for Environmental Advocacy ("MCEA"); (iv) North American Water Office and Institute for Local Self-Reliance ("NAWO/ILSR"); (v) No CapX ("NO"); (vi) Citizens Energy Task Force ("CETF"); and the Midwest Independent Transmission System Operator, Inc. ("MISO"). Other parties intervened but were less actively involved.

[4] Initially Applicants proposed single-circuit 345 kV structures (except for a section of the Brookings Project). The Upsizing Alternative generally proposes to use double-circuit capable structures but to only string one circuit until authorized to string the second circuit by the Commission in a later proceeding. The Upsizing Alternative uses the same 150-foot right of way. Ex. 121 at 16-17, 26 (Grivna Rebuttal). Initially the Upsizing Alternative will cost approximately 20% more than the original proposal with another 10% incurred when the second side is installed. Ex. 121 at 17 (Grivna Rebuttal); Ex. 88 at 3-5 (Stevenson Rebuttal); Ex. 120 at 4-5 (Lennon Rebuttal). The Upsizing Alternative provides the benefits of the original proposal, with enhanced expansion opportunities.

[5] The Upsizing Alternative is depicted on Exhibits 22-25. Copies of these four diagrams are appended to this Brief as Attachments A-D for the ALJ's convenience.

Commission approve the Upsizing Alternative summarized in Exhibit 311, reproduced below:[6]

Project	Segment Start	Segment End	Build Circuits	Build Voltage	Operate Voltage	In-service
Fargo	undefined near Fargo	undefined near Alexandria	Upsized	345 kV	345 kV	2015
Fargo	undefined near Alexandria	Quarry (new)	Upsized	345 kV	345 kV	2013
Fargo	Quarry (new)	Monticello	Upsized	345 kV	345 kV	2011
Brookings	Brookings County	Lyon County	Upsized	345 kV	345 kV	2013
Brookings	Lyon County	Hazel Creek	Upsized	345 kV	345 kV	2013
Brookings	Hazel Creek	Minnesota Valley	[] Upsized [] (Defer to Route)	345 kV	230 kV	2013
Brookings	Lyon County	Franklin	Double	345 kV	345 kV	2012
Brookings	Franklin	Helena (new)	Double	345 kV	345 kV	2012
Brookings	Helena (new)	Lake Marion	Upsized	345 kV	345 kV	2013
Brookings	Lake Marion	Hampton Corner (new)	Upsized	345 kV	345 kV	2013
LaCrosse	Hampton Corner (new)	North Rochester (new)	Upsized	345 kV	345 kV	2015
LaCrosse	North Rochester (new)	Chester	Single	161 kV	161 kV	2015
LaCrosse	North Rochester (new)	Northern Hills	Single	161 kV	161 kV	2011 or 2012
LaCrosse	North Rochester (new)	undefined near LaCrosse	Upsized	345 kV	345 kV	2015

II. SUMMARY

Transmission Certificates of Need are governed by Minn. Stat. § 216B.243 and Minn. R. Ch. 7849. Applicants have the burden to satisfy all applicable statutory requirements and the Commission's criteria found at Minn. R. 7849.0120 A-D. Essentially, Applicants must establish (i) the existence of one or more needs for the proposed facilities; (ii) that the proposed facilities address those needs; and (iii) that no more reasonable and prudent alternative in the record better addresses those needs.

[6] Applicants note that Exhibit 311 contains an error. It incorrectly reflected that the Hazel Creek -- Minnesota Valley segment would be "Single or Upsized." Applicants and OES agree the configuration for this segment is 345 kV double-circuit capable but operated at 230 kV. Ex. 307 at 27 (Rakow Surrebuttal)("I recommend that the Commission order the Hazel Creek – Minnesota Valley segment be constructed with double-circuit capable structures at this time."); Ex. 23 (Brookings Upsizing).

In this case, Applicants identified three separate need categories – community service reliability, system-wide growth, and generation outlet – that must be addressed soon to maintain reliable service to utility customers throughout the State. The 345 kV Projects address each of those needs while providing a solid platform for future coordinated transmission development. Coordinated development will be necessary for utilities to accommodate regional growth and to comply with State policies requiring deployment of renewable and non-renewable generation in the coming decade and beyond. The only two alternatives that were sufficiently developed in the record to qualify as alternatives 'in the record' are Applicants' original proposal and Applicants' Upsizing Alternative. Applicants' Upsizing Alternative is the alternative that should be selected by the ALJ.[7]

While some intervenors criticized isolated aspects of the claimed need, no party provided sufficient analysis overriding the multiple bases for needing new transmission in Minnesota and the broader region. Likewise, while these same parties criticized the original proposal and the Upsizing Alternative, it is undisputed that Applicants' proposals, in fact, address all of the needs identified in the Application. And none of these parties submitted viable alternatives as required by the rules. As a result, Applicants have satisfied their burden of proving that the Upsizing Alternative is the most reasonable and prudent alternative in the record.

A. <u>Transmission is Needed</u>

To construct large energy facilities, Minnesota law requires Applicants to demonstrate the "need" for them. There are many factors the ALJ must consider when determining whether Applicants have established need. As this Brief discusses below, Applicants have satisfied those factors by a preponderance of evidence.

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[7] OES offered a "500 kV Option" specific to the Fargo Project as a potential. Applicants understand that OES no longer supports the 500 kV Option. Ex. 307 at 8, 9, 21, 35-36 (Rakow Surrebuttal). And no party supports it as a more reasonable and prudent alternative for consideration.

Applicants presented three need categories: 1) community service reliability; 2) system-wide growth; and 3) generation outlet for expected generation. Much of the record developed in this case revolved around the need categories, whether and when those needs must be satisfied, and whether one subcategory of need – generation support for renewable generation – should be elevated above the others to justify conditions. These three need categories each provide important and independent bases to grant Certificates of Need. While Applicants expect significant new (including renewable) generation in the next decade, these lines are not dedicated to or intended for the exclusive use by renewable generation.

1. *Community Service Reliability*

Public utilities in Minnesota have a statutory obligation to provide safe, reliable and adequate service to their retail customers. To ensure the ability to serve the growing needs of customers, utilities must plan ahead to deploy transmission that will serve customers in the near and long terms. Applicants have demonstrated that several communities (sometimes referred to as "load centers") in the region need additional transmission capacity to enable continued reliable service.

Rochester and the Winona/La Crosse areas have significant near- and mid-term need for additional transmission support. Transmission planning scenarios have shown the need for an additional 345 kV connection that will provide an additional source of power and will overcome the critical load level contingencies.[8] The need for transmission the Winona/La Crosse area also supports a 345 kV connection.

[8] The record reflects that other transmission projects in the Rochester area could address the Rochester load serving need. Those additional projects, referred to as the Regional Incremental Generation Outlet ("RIGO") projects, have not yet been proposed or approved but preliminary study work suggests they could address Rochester's immediate load serving need. Even if the RIGO projects proceed and perform as described in this record, it does not eliminate the load serving need for the La Crosse 345 kV Project as the RIGO projects do nothing to support the Winona/La Crosse area needs. The presence of an additional 345 kV connection in the Rochester area will provide a significant source to the city that will accommodate expected growth for the foreseeable future. Ex. 98 at 1-4 (King Rebuttal); Ex. 99 at 2 (King Surrebuttal).

The St. Cloud area has experienced notable growth. New transmission is needed as soon as possible to address the critical contingency and provide support to this growing area. Likewise, the Alexandria area and the south zone of the Red River Valley (Fargo, Moorhead) have similarly experienced increased demand for electricity and need additional transmission soon to serve growing customer requirements.[9]

The Brookings Project will also enhance customer service capabilities in western Minnesota and the southern suburbs of the Twin Cities. Communities such as New Ulm, Redwood Falls, and fast-growing areas like Apple Valley and Lakeville will all be significantly benefited by the addition of a new 345 kV source.

2. *System-Wide Growth*

The evidence establishes that overall consumer demand for electricity has grown to the point where grid expansion is once again necessary to maintain regional reliability. Similar to prior efforts in the late '60s and '70s, that resulted in construction of the 345 kV ring around the Twin Cites and ties to the south and east, the time has come again for a general expansion of the high voltage grid. Like the approach taken 40 years ago, the grid should be expanded to accommodate not only the immediate identified needs, but in anticipation of growth for decades into the future. Overall, this is a more economical approach that results in more efficient land use. It is time to build the network for the future and to take a comprehensive view of future demands.

The CapX2020 initiative was formed to develop a coordinated and Statewide approach to transmission planning applying this long-term view. (Ex. 6 at 10-12

[9] It should be noted that the Bemidji – Grand Rapids 230 kV project (MPUC Docket No. E-017, E-015 & ET-06/CN-07-1222) ("Bemidji Project") helps address customer service issues in the North Zone of the Red River Valley (*e.g.*, Grand Forks). But the Bemidji Project does nothing to alleviate the growing customer service requirements in the South Zone. Ex. 67 at 13-14 (Kline Direct).

(Rogelstad Direct)). The CapX2020 utilities developed a plan for regional transmission expansion to serve reasonably expected growth in system-wide demand.

While there was considerable debate in the record as to the precise amount of Statewide demand growth by 2020, there has been no dispute that growth will be significant, certainly in the thousands of megawatts. (Ex. 9 at 3 (Rogelstad Rebuttal); Ex. 53 at 8 (Lacey Direct Updated Figure 6-6)). At most, slower growth only affects the timing of needed transmission expansion for regional reliability by a year or two and does not change the underlying fundamental premise that network expansion is necessary for long-term benefit. Even if forecasted demand growth is reduced due to the slowing economy and further updated forecasts (*e.g.*, Great River Energy's and Xcel Energy's 2008 Resource Plan Filings), the record establishes the lines are still needed to ensure a robust regional transmission system. Load growth as low as 2,000 MW in the next 12 years – a level not even alleged in this record – still justifies these projects. (Rogelstad 2b Vol. 83-84).[10] Consistent with the prescient and successful planning efforts of the 1960s-'70s, it is appropriate to proceed with the 345 kV Projects now to provide a strong platform for future demand growth and future grid expansion. And, in any event, the 345 kV Projects are needed for community service reliability and generation outlet needs as well. There is no evidence that a lower overall demand eliminates or even reduces those needs.

3. ***Generation Outlet***

The third category of need is to provide network improvements to support installation of significant amounts of both renewable and non-renewable generation to serve customer needs and to comply with State energy policies. In particular, a significant justification for the Brookings Project is to increase generation outlet from

[10] Q. "In your professional opinion, if there were only 2,000 megawatts of growth on the system by 2020, would it eliminate the need for the three transmission lines under consideration here today? A. I don't believe it would." Rogelstad 2b Vol. 84.

the Buffalo Ridge region from the projected 2010 level of approximately 1,200 MW to approximately 1,900 MW (depending upon the location of specific projects and other variables). While the Brookings Project is not dedicated only to wind generation, the record establishes significant interest that should result in this project facilitating the development of wind resources on the Buffalo Ridge. The generation support provided by the La Crosse and Fargo Projects was not quantified, but the presence of those projects will provide for a more robust system to facilitate energy transfers into Minnesota from neighboring states and support future generation projects.

OES provided an extensive generation need analysis that should be adopted. That analysis supports the need for additional transmission to facilitate both renewable and non-renewable generation additions in the coming decade. (Ex. 275 (Revised Interconnection Need Table)). This analysis took into account many factors and adjustments to ensure that the need for new generation was not overstated. *See e.g.*, Ex. 257 at 9, 15, 16 and 18 (Ham Direct). OES methodology considered reductions arising out of the new 1.5% energy conservation targets as well as the amount of wind generation that will be needed to satisfy the State's Renewable Energy Standards ("RES") requirements. OES concluded that 4,621-6,817 MW of new generation (3,160-4,927 MW of renewable generation and 1,269-2,094 MW of non-renewable generation are needed. (Ex. 275 (Revised Interconnection Need Table); Ex. 274 at 2 (Ham Surrebuttal)).

These generation levels are easily high enough to justify expansion of the network by building the three proposed projects. In fact, there is no dispute that in order to deploy all of the generation that will be needed over the next 15-20 years, transmission well beyond the 345 kV Projects will be needed. Indeed, the 345 kV Projects are merely the first step in building the system to facilitate new generation regardless of where that generation is built. (Ex. 1 at 1.13-1.14 (Application)).

B. 345 kV Projects Address Claimed Needs

The record establishes that the Upsizing Alternative addresses each of the three need categories for each of the 345 kV Projects.

- A 345 kV connection between the Twin Cities and La Crosse helps alleviate near-term load serving issues in communities along the line while simultaneously providing an important 345 kV connection that will allow for power transfers into Minnesota from generation to the south and east. (Ex. 98 at 2 (King Rebuttal)). It also provides for a robust system for future generation expansions in southeastern Minnesota, an area that is showing considerable interest in developing wind generation.
- A 345 kV connection from Fargo to the Twin Cities provides significant benefits by tying two major load centers more tightly together. (Ex. 67 at 17 (Kline Direct)). That major connection further addresses reliability concerns to several communities along the line. This project also increases the North Dakota Export ("NDEX") Limit, allowing increased transfers in the Red River Valley, an area that has shown significant interest in adding wind generation. (Ex. 67 at 12 (Kline Direct).
- The Brookings Project provides load serving benefits to communities in the project area while adding several hundred megawatts of generation outlet from the Buffalo Ridge area, which should facilitate wind generation development.

C. Significant Transmission Planning Study Work

Considerable transmission planning study work was undertaken over several years to develop the specific projects that are the subject of this proceeding. The studies consistently concluded that (i) the 345 kV Projects are the best solution to simultaneously address all three need categories, and (ii) the 345 kV Projects (along with the Bemidji Project) are common to any reasonable future scenario and thus are appropriate foundational improvements to the regional transmission system.

1. *CapX2020 Vision Plan*

In 2004, the CapX2020 utilities joined to develop a comprehensive Statewide transmission planning approach to meet increasing electricity demand in Minnesota and the surrounding area. The CapX2020 utilities began their joint initiative by developing the Vision Plan, a study "intended to be a high level study that would provide a blue-print for future transmission development" of Minnesota and the surrounding region. (Ex. 6 at 11 (Rogelstad Direct)). The output of the Vision Plan shows that regional growth in the last three decades requires significant additional transmission infrastructure. The Vision Plan concludes that by adding elements to the States' 345 kV network, the transmission system can continue to operate reliably while accommodating substantial future growth. (Ex. 1 at Apx. A-1 (Vision Plan)). While the Vision Plan did not develop the specific projects subject to this proceeding; it did provide a general, long-range analysis, helped develop a better understanding of the issues the State will be facing without additional infrastructure, and provided an analytical framework to guide project analysis. (Ex. 6 at 11 (Rogelstad Direct)).

2. *Individual Studies*

At roughly the same time, utility engineers were conducting a series of project-specific transmission studies to assess and develop alternatives for specific projects throughout the State. These three studies – the Southeastern Minnesota and Southwestern Wisconsin Reliability Enhancement Study (the "Rochester/La Crosse Study"), the Red River Valley/Northwest Minnesota Load-Serving Transmission Study (the "TIPS Update"), and the Southwest Minnesota – Twin Cities EHV Development Electric Transmission Study ("EHV Study") – were all initiated to address the increasing customer service needs in communities throughout the State and to analyze alternatives that could provide a transmission outlet for generation from the Buffalo Ridge to the load centers. (Ex. 6 at 11 (Rogelstad Direct); Ex. 1 at Apx. A-2, A-3, A-4 (Project Studies)).

Based on all of this study work, Applicants developed the 345 kV Projects (as well as a fourth project – the Bemidji Project). The Application and record result from that effort. Indeed, the study work demonstrates that the 345 kV Projects are needed to meet community load serving needs in several communities, to ensure long-term reliability of the regional transmission system, and to provide additional generation outlet capability. (Ex. 56 at 10-11 (Webb Direct); Ex. 6 at 16-17 (Rogelstad Direct)). While there was considerable debate in the record as to the precise amount of demand growth, there was no real dispute that growth of several thousand megawatts will occur and that at these load levels the facilities are needed for regional reliability. (Ex. 274 at 2 (Ham Surrebuttal); Ex. 9 at 3 (Rogelstad Rebuttal); Ex. 53 at 8 (Lacey Rebuttal Updated Figure 6-6)). And, there was no reasonable challenge to the substation load data supporting the community needs or to the MISO queue data supporting the outlet need in the Buffalo Ridge.

In addition, MISO studied the transmission system expansions that would be needed to ensure the reliability of the system and to identify needed expansion to support the competitive supply of electric power. MISO independently confirmed that the 345 kV Projects are needed for short-term to long-term reasons. MISO's analysis determined these projects fall into short-term to intermediate-term planning horizons, that will be needed within the next 5 to 7 years. MISO included these projects as a part of the base plans upon which the longer term plans are being developed and analyzed. MISO also concluded the 345 kV Projects should be built as proposed because a build-out of additional 345 kV facilities is needed meet long-term needs, along with regional power transfers and local reliability needs. (Ex. 56 at 8-10 (Webb Direct)). Through its work, MISO confirmed that the La Crosse Project and Fargo Project are the best alternatives for addressing the community reliability concerns facing communities in those areas; and Brookings Project is the best alternative for addressing generation outlet and community reliability concerns. (Ex. 56 at 17-37 (Webb Direct)).

3. ***Recent Business Arrangements***

More recently, many of the CapX2020 utilities formalized their commitment to this coordinated planning concept through the execution of certain agreements that create a method for moving the CapX2020 business arrangements forward. These include an overall "Participation Agreement" as well as "Project Development Agreements" ("PDAs"), which spell out parties' rights and obligations for pursuing the 345 kV Projects.[11] (Ex. 2, Apx. B-1, B-2, B-3, and B-4 (Project Agreements)). Under the PDAs, Xcel Energy and Great River Energy, as Development Managers, have the responsibility to seek and obtain major permits for the 345 kV Projects proposed in the Application. Xcel Energy and Great River Energy are not only Applicants on behalf of themselves and the other CapX2020 participants, they will also be in charge of implementing the Certificates of Need, if they are granted.

The other signatories to the PDAs have the right, but not the obligation, to take some ownership share of the 345 kV Projects after major permits (including Certificates of Need and route permits) have been issued. This means that currently the final ownership structure is not known. But the determination of need does not require identifying final ownership; Applicants will implement the Commission's order.

D. <u>No More Reasonable and Prudent Alternatives in the Record</u>

The third prong of the overall analysis is to determine whether Applicants or some other party submitted a more reasonable and prudent alternative into the record

[11] The signatories to the La Crosse Project PDA are Dairyland Power Cooperative, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, Wisconsin Public Power Inc., Northern States Power Company – Wisconsin and Xcel Energy. The signatories to the Fargo Project PDA are Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company and Xcel Energy. The signatories to the Brookings Project PDA are Great River Energy, Central Minnesota Municipal Power Agency, Missouri River Energy Services, Otter Tail Power Company and Xcel Energy. Ex. 1 at 1.25-1.26 (Application).

that would be a better choice for addressing the claimed needs. With the exception of the Upsizing Alternative, no other party submitted alternatives for consideration.

1. *Upsizing*

As the case developed, it became evident that parties were interested in exploring more robust alternatives that would provide the potential for future expansion and maximize the right-of-way corridors. OES sponsored testimony that criticized aspects of the original proposal as being too small and not focused on the long-term development of the grid. (Ex. 282 at 71-72 (Rakow Direct)). MCEA witness Larry Schedin similarly analyzed whether robust alternatives would better satisfy the identified needs. (Ex. 177 at 6, 23 (Schedin Direct)). And MISO's witness, Jeffrey Webb, testified it is very common for 345 kV transmission to be double-circuited. (Webb 5a Vol. at 49, 5b Vol. at 52-53).

As a result of this interest, Applicants analyzed whether a more robust alternative would be appropriate. Applicants concluded that "it is appropriate to plan and implement the transmission system with long-term goals in mind [and] it is appropriate to go a step beyond the current standard and examine the long-term use and potential benefits of the proposed facilities to meet needs beyond the foreseeable future." (Ex. 121 at 8 (Grivna Rebuttal)). Applicants reviewed five variations of upsizing and provided that analysis in Walter Grivna's testimony. While there is uncertainty as to how the future system will develop, Applicants concluded that it would be most appropriate to build the 345 kV Projects with larger structures that can be modified to accommodate a second circuit in the future. This became the Upsizing Alternative.

The Upsizing Alternative has been endorsed by both OES and MCEA. It provides the necessary electrical performance and addresses all of the needs on the same basis as the original proposal. While the double-circuit compatible structures are somewhat taller and more expensive, utilizing them on the front end will cost less than rebuilding them in the future or building additional projects on new right-of-way. By deferring some of the capital expenditures for the second circuit, Applicants are able to more closely match that investment with future growth.[12]

2. *Absence of Other Alternatives*

With the exception of the Upsizing Alternative, no other alternatives were submitted for consideration. The "commission shall consider only those alternatives proposed before the close of the public hearing and for which there exists substantial evidence on the record with respect to each of the criteria listed in part 7849.0120." Minn. R. 7849.0110 (emphasis added). Mere criticism of Applicants' proposal does not satisfy this rule. Claims that Applicants could have developed other alternatives do not constitute alternatives under this rule. And arguments that other technologies may develop in the future that could affect future growth and expansion are not alternatives in this record. Thus, the ALJ should decide based on the two alternatives that are in the record – the application proposal and the Upsizing Alternative.

E. No Unreasonable and Unnecessary Conditions

Some parties proposed that conditions be attached to any Certificates of Need granted in this case. OES suggested reporting requirements and procedural conditions, which are acceptable to Applicants. Other parties seek substantive conditions that attempt to limit the use of the projects and would impose generation-related requirements on these transmission projects.

Those proposed conditions fall within two main categories: (i) require development of dispersed renewable generation ("DRG"), and small community-based ("C-BED") wind projects as a condition for building these lines, and (ii) "lock

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[12] Applicants' acknowledge that they could not string the second circuit without obtaining a certificate of need or other regulatory approvals in a subsequent proceeding. Ex. 121 at 32, 36 (Grivna Rebuttal).

up" the firm transmission capacity created by the 345 kV Projects only for wind generation. Such conditions are not supported or necessary, would increase consumer costs and risks, and mix generation policy with transmission policy. Transmission planning is separate from generation, and does not generally address fuel type or the detailed generation questions. Rather, transmission planning is concerned with the open-access and non-discriminatory delivery of electricity to customers, from whatever source is authorized and available.

The extended debate in this record over fuel type and generation policy is more appropriately addressed in resource planning and other proceedings where all appropriate stakeholders can develop a complete record on all of the relevant issues. The purpose of <u>this</u> proceeding is to determine whether Applicants have met the statutory requirements to obtain Certificates of Need for the 345 kV Projects, regardless of what fuel type or generation uses the lines.

Applicants respectfully request that the ALJ and Commission reject imposing generation-related conditions. First, NAWO/ILSRs' desire for guaranteed deployment of DRG and C-BED projects (see Alholinna 10 Vol. 44) is not the appropriate subject matter for conditions for a transmission Certificate of Need. While Applicants support the development of DRG, C-BED, and other renewable generation projects, this transmission docket is not the right venue for those decisions. Second, imposing requirements to lock up any new firm capacity only for wind generation disregards the three separate needs established on the record. Third, the State's RES requirement does not support burdening Certificates of Need with conditions. (Ellison 21 Vol. 17-21). The Commission does not need these conditions to ensure RES implementation. Fourth, the RES is only one State policy that must be addressed in making a decision and other policies support rejecting the conditions. Fifth and most importantly, imposing these conditions would be detrimental to utility customers and would interfere with both transmission and generation policymaking. (Ex. 132 at 26, 29-33 (Alders Rebuttal)).

Applicants understand that a motivation behind the proposed conditions is a desire to prevent the 345 kV Projects from being used by the proposed Big Stone II generating station. But the record already establishes that Big Stone II would depend upon its own transmission and would not use any of the firm transmission capacity associated with this case. Speculations about possible actions the Commission might take in another docket and what possible actions Big Stone II might take does not justify conditions.

Applicants respectfully request the ALJ and Commission focus this proceeding on whether Applicants met the requirements for transmission Certificates of Need and direct those parties who are interested in generation policy to proceedings that are intended for those discussions (resource plan and generation-related proceedings).

III. PROCEDURAL BACKGROUND

See Applicants' Proposed Findings of Fact, Conclusions of Law, and Recommendation for a recitation of the procedural history in this Docket.

IV. LEGAL REQUIREMENTS

The principal legal requirements for transmission Certificates of Need are found in Minn. Stat. § 216B.243, subd. 3 and 3a, together with the Commission's criteria for Certificates of Need in Minn. R. 7849.0120 A-D. In addition, Minn. Stat. § 216.2422, subd. 4 (renewable energy preference); Minn. Stat. § 216B.2426 (distributed generation); Minn. Stat. § 216B.1691 (RES); and Minn. Stat. § 216B.1612 (C-BED requirements), and Minn. Stat. § 216H.03 (carbon) must be taken into account when considering a Certificates of Need request.

A. Legal Standard and Burden of Proof

Section 216B.243 provides that a Certificate of Need is required prior to the construction a "large energy facility" in Minnesota. Minn. Stat. § 216B.243, subd. 3. It is undisputed that the transmission lines included in the 345 kV Projects all fall within this statutory definition.[13] Specifically, the statute provides:

> No large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need.

Applicants bear the burden of proving the claimed need for a proposed transmission line. *See* Minn. Stat. § 216B.243, subd. 3. The burden of proof in this proceeding is proof by a preponderance of the evidence. Minn. R. 1400.7300, subp. 5.

Applicants' burden of proof is met by providing evidence establishing the needs and showing that the proposed alternative is a reasonable and prudent way to satisfy the articulated needs. It is not Applicants' burden to disprove the existence of all other potential alternatives or to prove the absence of theoretical alternatives.

To the contrary, the burden falls on other parties to introduce alternatives into the record for consideration and then to establish that any such alternatives are more reasonable and prudent and should be chosen. These rules place on the <u>proponent of the alternative</u> the burden of proving that any alternative it wishes to sponsor is (i) sufficiently presented in the record to be considered, and (ii) is more reasonable and prudent than the applicant's proposal. If a party wants a particular alternative to be considered, that party must make sure that sufficient evidence is submitted to satisfy the Commission's requirement that "only those alternatives proposed before the close of the public hearing and for which there exists substantial evidence on the record

[13] Minn. Stat. § 216B.2421 defines a large energy facility as "any high-voltage transmission line with a capacity of 200 kilovolts or more and greater than 1,500 feet in length." Minn. Stat. § 216B.2421, subd. 2(2).

with respect to each of the criteria listed in part 7849.0120" be considered. Minn. R. 7849.0110.

Some parties in this case argued that the rules and statute should be construed to require the project proponents to prove the absence of any possible alternative. This argument necessarily means that Applicants would have to 'prove the negative', a legal impossibility.[14] The Minnesota Court of Appeals has held that a Certificate of Need applicant is <u>not</u> required "to face the extraordinary difficulty of proving that there is not a more reasonable and prudent alternative" but that, instead, the onus is on the other party to "demonstrate that there is a more reasonable and prudent alternative to the facility proposed by the applicant."[15] Only when the other party demonstrates a "more reasonable and prudent alternative," will a permit be denied.[16]

B. <u>Lack of Other Alternatives on the Record</u>

As this case proceeded, OES conducted considerable analysis of Applicants' proposal. In excess of 200 information requests (including subparts) were asked and answered. OES performed its own independent review of the proposal and considered whether the proposal was needed and whether the proposal provided good economic value to consumers. OES provided expert testimony on the

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[14] *See e.g.*, *In re Application of the City of Hutchinson for a Certificate of Need to Construct a Large Nat'l Gas Pipeline*, No. A03-99, 2003 WL 22234703, at *7 (Minn. App. Sept. 23, 2003); *In re Application of Minnesota Pipeline Co. for a Certificate of Need for a Large Petroleum Pipeline*, MPUC Docket No. PL-5/CN-06-2, Order Granting Certificate of Need, 2007 WL 1804327, at *6 (MPUC Apr. 13, 2007). To require, instead, that a party prove the negative is to require proof of the impossible, which would be an unreasonable and absurd burden. The Commission must presume that the legislature did not intend results that are absurd or unreasonable. *Country Joe, Inc. v. City of Eagan*, 548 N.W.2d 281, 284 (Minn. App. 1996); *Dayton Hudson Corp. v. Johnson*, 528 N.W.2d 260, 262 (Minn. App. 1995) (concluding that absurd construction must be avoided).

[15] *In re Application of the City of Hutchinson*, 2003 WL 22234703 at *7. Courts in other contexts reject requiring parties to achieve the logically impossible feat of proving a negative fact. *See e.g.*, *Mitchell v. Volkswagenwerk, AG*, 669 F.2d 1199, 1204-05 (8th Cir. 1982) (applying Minnesota law when holding that the law is "not intended to create a rule which requires the plaintiff to assume an impossible burden of proving a negative fact").

[16] *In re Application of the City of Hutchinson*, 2003 WL 22234703 at *7.

Application. While OES often used different methodologies and analytical techniques, it reached substantially the same conclusions as Applicants.

MCEA likewise asked a number of information requests and provided analysis of the Application. Notably, MCEA included the expert testimony of an experienced electrical engineer – Larry Schedin[17] – who confirmed that the 345 kV Projects are needed. While Applicants disagree with MCEA's policy position on conditions, Applicants appreciate the thoughtful and thorough review MCEA performed on the Application and the constructive approach they took at the hearings.

MISO also provided an independent review of the proposal and concluded that the 345 kV Projects are needed.

Other parties asked fewer (if any) information requests and did little (if any) independent analysis of the Application. While these parties were critical of some aspects of Applicants' proposal, they provided no meaningful alternatives and no meaningful analysis from which the ALJ could reach a contrary result.

The development of a fully formed alternative to Applicants' proposal would necessarily require the submission of expert testimony as it would require technical electrical engineering verification.[18] Here the only engineering experts to review the Application and provide an opinion about it (Mr. Schedin and Mr. Webb) agreed with Applicants' position. Other opponents failed to offer any alternatives supported by any expert testimony and as a result, no meaningful alternative was demonstrated by a preponderance of the evidence on the record. Minn. R. 7849.0120(B).

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[17] Larry Schedin "conducted the design and analysis studies for the 345 kV loop around the Twin Cities and various transmission projects in southwestern, central and southern Minnesota at 69 kV, 115 kV and 161 kV." Ex. 177 at 2 (Schedin Direct).

[18] *Blatz v. Allina Health System*, 622 N.W. 2d 376, 388 (Minn. Ct. App. 2001) ("[W]hether expert testimony is required depends on the nature of the question to be decided by the trier of fact and on whether technical or specialized knowledge will assist the trier of fact.").

C. Commission Decision Criteria

Minn. Stat. § 216B.243, subd. 3 requires the Commission to take into account all of the decision criteria set forth in the statutes. The Commission's enabling rules lay out a list of 12 criteria that must be satisfied. Minn. R. 7849.0210. These criteria and the statutory requirements are described in detail in Section VII of this Brief. The Commission has discretion in determining need and the Commission must consider many factors in reaching its decision. The statutory requirement coupled with the Commission's decision criteria provide for a variety of factors and considerations that must be taken into account when deciding whether to grant Certificates of Need for the 345 kV Projects. All of the factors must be applied in light of the record that was developed in this case. The remainder of this Brief analyzes the record as well as a discussion of how each one of the statutes and rules has been satisfied.

V. THE RECORD

A. CapX2020 Business Arrangements

CapX2020 is a joint initiative of transmission-owning electric utilities. Currently, there are 11 utilities that are participating in the CapX2020 initiative including: (1) CMMPA, (2) Dairyland, (3) Great River Energy, (4) Minnesota Power, (5) Minnkota,[19] (6) MRES, (7) Otter Tail, (8) RPU, (9) SMMPA, (10) WPPI, and (11) Xcel Energy. (Ex. 64 at 12 (McCarten Direct)). This collaborative group formed to address existing and emerging needs in the overall electric transmission system.

A group of the CapX2020 utilities have formalized their commitment to coordinated regional planning through the execution of the Participation Agreement.[20] Together, the participants intend jointly and cooperatively to: (i) pursue the planning and coordination of studies or potential projects; (ii) develop, and coordinate project

[19] Bemidji Project only.

[20] The Participation Agreement is attached as Appendix B-1 to the Application. Ex. 2 at Apx. B-1 (Application).

standards to promote an efficient and reliable system; and (iii) coordinate the cooperative use of existing facilities. The Participation Agreement does not require that participants construct or own any transmission upgrades or expansions, but it is intended that such upgrades or expansions may be the subject of other agreements and arrangements among the participants and, in some instances, other parties. (Ex. 1 at 1.24 (Application)). In addition, the Participation Agreement facilitates the governance of the commercial relationship *vis a vis* CapX2020. (*Id.* at 1.25)).

In February 2007, a group of the CapX2020 utilities entered into one or more of three Project Development Agreements[21] ("PDAs") associated with the 345 kV Projects.[22] These PDAs provide a framework for the initial development phase of the 345 kV Projects. The signatories have agreed to pursue and fund development work for the projects in a collaborative manner. (Ex. 64 at 13 (McCarten Direct)). The participants agreed to determine the recommended alignment, end points and interconnection of the proposed configuration; estimate the cost and schedule; obtain State and federal regulatory approvals and consents; and engage in other project related studies or analyses. Each signatory has agreed to absorb a specified percentage of the development costs associated with a given project. Each PDA identifies a "lead" utility or a "Development Manager" that is responsible for obtaining major permits and developing and implementing the project if construction is authorized. Great River Energy serves as Development Manager for the Brookings Project; Xcel Energy serves as Development Manager for the Fargo Project and the La Crosse Project. (Ex. 1 at 1.26 – 1.27 (Application); Ex. 64 at 13 (McCarten Direct)).

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[21] The three PDAs are attached as Appendices B-2-B-4 to the Application. Ex. 2 at Apx. B-2-B-4 (Application).

[22] The signatories to the La Crosse Project PDA are Dairyland Power Cooperative, RPU, SMMPA, WPPI, Northern States Power Company – Wisconsin and Xcel Energy. The signatories to the Fargo Project PDA are Great River Energy, Minnesota Power, MRES, Otter Tail and Xcel Energy. The signatories to the Brookings PDA are Great River Energy, CMMPA, MRES, Otter Tail and Xcel Energy.

As Development Managers, Xcel Energy and Great River Energy are responsible to obtain all major permits for the 345 kV Projects, including these Certificates of Need. They are also responsible to develop the projects on behalf of themselves and the other PDA signatories. (Ex. 1 at 1.27 (Application); Ex. 64 at 13 (McCarten Direct)). They coordinate and manage the permitting process, engineering, procurement and future construction of the proposed lines, regardless of who ultimately owns any of the lines. Xcel Energy and Great River Energy have committed to take responsibility for the implementation of the Commission's order in this Docket as required by Order Point 1 of the Exemption Order. (Ex. 1 at 1.27 (Application); Ex. 64 at 13-14 (McCarten Direct)).

Once all critical permits have been obtained, the PDAs provide the opportunity for participants to decide whether to take an ownership stake in a project. At that time, each utility has the option to (i) take ownership up to a designated level, (ii) take some lesser percentage, or (iii) "opt out" of ownership entirely. (Ex. 1 at 1.28 (Application); Ex. 64 at 14-15 (McCarten Direct)). The current project development percentages (and potential/non-binding ownership percentages) are set forth below:

Potential Development of 345 kV Projects

Project Name:	La Crosse Project	Fargo Project	Brookings Project
Applicable Project Development Percentage			
Central Minnesota Municipal Power Agency	--	--	2.2%
Dairyland Power Cooperative	11.0%	--	--
Great River Energy	--	25%	16.5%
Minnesota Power	--	14.7%	--
Missouri River Energy Services	--	11.0%	5.1%

Otter Tail Power Company	---	13.2%	4.1%
Rochester Public Utilities	9.0%	--	--
Southern Minnesota Municipal Power Agency	13.0%	--	--
Wisconsin Public Power	3.0%	--	--
Xcel Energy	64.0%	36.1%	72.1%
Totals:	100%	100%	100%

(Ex. 1 at 1.29 (Application)).

While these percentages can be thought of as potential ownership interests in the finished projects, there are no guarantees that the participants will all commit to the capital investments necessary to support their full interest. As a result, Applicants have attempted to keep the permitting process flexible to accommodate a variety of future scenarios. Applicants respectfully request that the ALJ and the Commission maintain that flexibility in recommendations arising out of this proceeding.[23]

B. <u>Studies</u>

In 2004, CapX2020 utilities began conducting engineering studies to establish a comprehensive plan for development of transmission infrastructure to meet the increasing demand for electricity in Minnesota and the surrounding area through the year 2020. One study, known as the Vision Plan, was a comprehensive planning study to look at long-range needs and goals and provide a high level review of the electrical system 10-to 25-years out, with broad assumptions, to provide a blueprint for the future. (Ex. 6 at 5 (Rogelstad Direct); Ex. 1 at Apx. A-1 (Vision Plan)). The Vision Plan examined what transmission system additions would need to be developed to accommodate load growth increases of several thousand megawatts by 2020.

[23] Applicants respectfully request that the Certificates of Need in this proceeding be issued in their name but also recognize that Applicants are acting on behalf of themselves and the other CapX2020 utilities who may ultimately own some portion of one or more of the projects.

The 345 kV Projects and the Bemidji Project (collectively, the "Group 1 Projects") were identified as the foundation upon which the entire transmission expansion plan could be built while addressing immediate system reliability issues. The utilities also undertook three individual engineering studies to evaluate facilities to address specific needs. These "Specific Studies" are shorter term (1-to 10-year time horizon) and focused on specific circumstances. (Ex. 6 at 5 (Rogelstad Direct)).[24]

C. Description of the Projects

1. *La Crosse Project*

The La Crosse Project, includes 345 kV and 161 kV facilities. This project consists of an approximately 150-mile, 345 kV transmission line between the southeast corner of the Twin Cities at a new Hampton Corner Substation, to a new North Rochester Substation and from there to a La Crosse, Wisconsin area substation. (Ex. 83 at 3 (Stevenson Direct); Ex. 1 at 2.2 (Application)). Depending upon the final route selected, Applicants also propose to construct two 161 kV lines connecting the new North Rochester Substation to the Northern Hills and Chester substations in the Rochester area. Applicants propose to use approximately 150 foot tall structures that use a 150 foot right-of-way for the 345 kV segments. (Ex. 121 at 17 (Grivna Rebuttal)).

Under the Upsizing Alternative, a number of detailed variations are required that are depicted on Exhibit 24 and 25 (appended to this Brief as Attachments C and D). Applicants propose to construct the North Rochester to La Crosse area 345 kV line by 2015 and the Hampton – North Rochester 345 kV line and North Rochester – Chester 161 kV line by 2015. Applicants request flexibility to construct the Northern

[24] The Rochester/La Crosse Study, examined a regional solution to the load serving needs in the Rochester and Winona/La Crosse areas. The TIPS Update evaluated how best to address the load serving needs in Alexandria and the South Zone of the Red River Valley. The EHV Study, studied how best to increase generation support capability in the Buffalo Ridge area. All of these studies provide the foundation for the 345 kV Projects. Ex. 1 at Apx. A-2, A-3, A-4 (Project Studies).

Hills – North Rochester 161 kV line by 2011 (unless the RIGO projects are permitted, in which case, by 2013). (Ex. 83 at 10 (Stevenson Direct)).

The La Crosse Project is proposed to connect the North Rochester Substation to a substation in the La Crosse, Wisconsin area. The Mississippi River must be crossed. At this juncture, there are three potential river crossings that have been identified: Alma, Winona and La Crescent.[25] Regardless of where the line crosses the river, it will connect at a La Crosse area substation. (Ex. 98 at 5-6 (King Rebuttal)).

In pre-filed testimony, Dr. Steve Rakow stated a preference for one of the river crossings, opining that the "best information at this time indicates that the Alma crossing appears to have both the least cost and the least environmental impact. Therefore, the Commission should order the Alma crossing in this proceeding." (Ex. 307 at 25 (Rakow Surrebuttal)). Dr. Rakow did recognize, however, that at this time in this record the impacts are similar and the Commission could deem either endpoint reasonable in the need case and leave the final decision for the Commission's future routing docket where a full environmental impact statement will be developed. (Ex. 307 at 25 (Rakow Surrebuttal)). Applicants agree and respectfully request that the appropriate river crossing be decided in the Minnesota route and Wisconsin proceedings. Consequently, Applicants request that the Commission issue a Certificate of Need granting Applicants the flexibility to terminate the 345 kV line at a La Crosse area substation. (Ex. 98 at 6 (King Rebuttal)).

Applicants estimate that the La Crosse Project (assuming an Alma river crossing) will cost between $389 million to $415 million in 2007 dollars.[26] (Ex. 89 at 4

[25] Initially a river crossing at Trempealeau had been proposed. Applicants determined this was not a viable option because 1) there is no existing transmission line in the area, 2) the area had more residences than originally expected, and 3) other three alternatives have existing transmission lines in place. Ex. 128 at 9-10 (Rasmussen Direct).

[26] All of the cost estimates provided herein are subject to change as they can be affected considerably by various variables such as the timing of construction, availability of construction crews and components, and the ultimate route selected by the Commission.

(Stevenson Surrebuttal)). Applicants estimate that for the La Crescent and Winona crossings, the La Crosse Project will cost between $407 million to $432 million in 2007 dollars. (Ex. 89 at 4 (Stevenson Surrebuttal)).

2. *Fargo Project*

The Fargo Project consists of a 345 kV connection between the existing Monticello Substation and a new or existing Fargo, North Dakota area substation. (Ex. 312 at 1 (Kline Final Rebuttal)). The overall length of the Fargo Project will be approximately 210 to 270 miles depending on the route selected. (Ex. 83 at 11 (Stevenson Direct)). Applicants have proposed to use approximately 150-foot tall structures that use a 150-foot right-of-way. (Ex. 121 at 17 (Grivna Rebuttal)). All segments of the Fargo Project will use the Upsizing Alternative as shown in Exhibit 22, appended to this Brief as Attachment A. The permitting process is currently projected to be completed by 2010. (Ex. 83 at 14 (Stevenson Direct)). The projected in-service date for this project is 2015. The current estimated capital cost for this project is between $500 million and $640 million in 2007 dollars. (Ex. 88 at 5 (Stevenson Rebuttal)).

3. *Brookings Project*

The Brookings Project is comprised of approximately 200 miles of 345 kV segments between the new Hampton Corner Substation and the existing Brookings County Substation near White, South Dakota. The project includes an approximately 25-mile, 345 kV circuit from the Lyon County Substation near Marshall, Minnesota to a new Hazel Creek Substation southwest of Granite Falls, Minnesota and an approximately eight to 10 mile, 230 kV transmission line from Hazel Creek Substation to the existing Minnesota Valley Substation. The Lyon County – Hazel Creek – Minnesota Valley segments will replace the existing Lyon County – Minnesota Valley

115 kV line. Applicants have proposed to use approximately 150-foot tall structures that use a 150-foot right-of-way. (Ex. 121 at 17 (Grivna Rebuttal)).

In developing the Upsizing Alternative, Applicants have made several specific changes to the project description in the Application, as depicted in Exhibit 23 appended to this Brief as Attachment B. One such change is that Applicants propose that the Minnesota Valley Substation – Hazel Creek Substation 230 kV segment be constructed to double-circuit 345 kV specifications but operated at 230 kV.[27] This modification is being made to better integrate with potential future projects. (Ex. 107 at 1-2 (Alholinna Rebuttal)). It would also decrease the flow on the Granite Falls – Willmar 230 kV line during the loss of a new Hazel Creek – Blue Lake line. (Ex. 121 at 38-39 (Grivna Rebuttal)).

The projected in-service date for the middle portion of the Brookings Project (from Lyon County to Helena) is 2012. The eastern portion of this line (from Helena to Hampton Corner) and the western portion (Brookings County to Lyon County) are currently scheduled to be in-service by 2013. (Ex. 116 at 8 (Lennon Direct)). The estimated cost of the Brookings Project is estimated to be between $650 million to $725 million in 2007 dollars. (Ex. 120 at 4-5 (Lennon Rebuttal)).

4. ***System Improvements to Support the 345 kV Projects***

Substantial high voltage additions to the transmission system generally require upgrades to the existing lower voltage system to ensure capacity of the lower voltage circuits is not exceeded in certain circumstances. (Ex. 1 at 2.17-2.18 (Application)). Applicants have identified certain upgrades to lower voltage parts of the system that may need to be implemented as part of the 345 kV Projects. (Ex. 1 at 2.17-2.18

[27] In the Application, Applicants proposed a 230 kV connection between Hazel Creek and Minnesota Valley. As part of the upsizing proposal, Applicants modified the configuration to be a single circuit, single pole, 345 kV connection, but operated at 230 kV. Ex. 121 at 11 (Grivna Rebuttal). Applicants have adjusted the proposal in response to OES recommendation that this segment also be constructed on double-circuit structures.

(Application)). These upgrades fall within the $70-$100 million range.[28] The final determination of the appropriate underlying system improvements will be made in MISO interconnection studies. (Alholinna 10 Vol. 89-91, 97-98). Appended to this Brief as Attachment E is a compilation of these known projects.

5. *Upsizing Alternative*

As noted previously, Applicants initially proposed that the 345 kV Projects be constructed largely on single circuit poles except for those portions already planned to be double-circuited.[29] In prefiled testimony, both OES and MCEA argued that Applicants' original proposal lacked long-term vision and did not do enough to create an adequately sized transmission system that would provide value for years or even decades to come. They suggested consideration of double-circuit 345 kV or even 500 kV configurations. (Ex. 282 at 20-21 (Rakow Direct); Ex. 177 at 23 (Schedin Direct)).

In response, Applicants reexamined all three of the 345 kV Projects with a view toward the longer term future. Applicants recognized that their initial proposals were sufficient to meet the immediate needs, but that there could be benefits to building for future expansion on the same structures. (Ex. 121 at 9 (Grivna Rebuttal)).

Applicants determined that the double-circuit-compatible or Upsizing Alternative is the best-available option for all 345 kV Projects.[30] By deploying only the first circuit, Applicants obtain all of the benefits of the 345 kV Projects while

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[28] The necessary underlying system improvements is unaffected by the upsized proposal because no new circuits are being added immediately. Ex. 121 at 17 (Grivna Rebuttal).

[29] In addition there will be circumstances where elements of the Projects may be co-located with existing transmission line on double-circuit structures. Ex. 121 at 31-32 (Grivna Rebuttal); Exhs. 22-25 (Upsizing Drawings).

[30] The terms "double-circuit compatible" mean Applicants would build structures to carry two 345 kV lines but only string the first circuit now as part of the Project. Ex. 121 at 10 (Grivna Rebuttal). The second circuit would be strung at a later date when circumstances warrant. Ex. 121 at 10 (Grivna Rebuttal).

providing the structures that can accommodate a future second circuit.[31] Designing structures to add additional capacity is not only "prudent" but also "pretty much standard practice" in other parts of the Midwest. (Webb 5b Vol. 52-53).

VI. THREE CATEGORIES OF NEED

These 345 kV Projects are designed to address three separate need categories: (1) community service reliability, (2) system wide growth, and (3) generation support, including outlet that supports renewable generation. (Ex. 282 at 12 (Rakow Direct); Ex. 1 at 1.4 (Application)). Each need is important and must be addressed by any alternative. (Ex. 303 at 7 (Rakow Rebuttal); Ex. 307 at 32 (Rakow Surrebuttal)).

A. <u>Community Service Reliability</u>

1. *Community Service Reliability Needs Summary*

The La Crosse Project and the Fargo Project will alleviate near term community service reliability concerns in the Rochester and the Winona/La Crosse area, as well as in St. Cloud, and the South Zone of the Red River Valley, including the Alexandria area (Ex. 1 at 1.4-1.9 (Application)). The demand for electrical power in these communities can no longer be reliably supported by existing transmission lines.

As summarized by Mr. Webb:

> These two 345 kV projects are especially effective in addressing future reliability needs in the Twin Cities and surrounding areas and will provide for sustained reliability for many years. The projects will provide long-term local reliability in both the northern and southern Red River Valley areas, as well as in the Alexandria, St. Cloud, Rochester, and La Crosse areas. As such, the projects represent a prudent application of higher voltage supply solutions to address a variety of reliability needs in many different areas of the system

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[31] The portions of Brookings Project initially proposed as double-circuit 345 kV, Lyon County – Franklin – Helena, will still be strung immediately as a double-circuit line. *See* Ex. 23 (Brookings Upsizing).

> simultaneously and to provide for these needs for the foreseeable future.

(Ex. 56 at 32 (Webb Direct)).

Likewise, the Brookings Project will provide local reliability benefits to the communities in the project area. (Ex. 56 at 36 (Webb Direct); Ex. 104 at 7 (Alholinna Direct)). The New Ulm and Redwood Falls area will benefit from the presence of this project because the new Franklin 345/115 kV transformer will provide a much needed new power supply point to the 115 kV system in the south west to south central part of the State. In addition, the Hazel Creek – Lyon County 345 kV segment will strengthen the system's ability to serve the Granite Falls area and surrounding territory, as far east as Sacred Heart, north and west to Montevideo and Clara City, and south to the Marshall area. (Ex. 104 at 7-8 (Alholinna Direct)). The Brookings Project will also provide community reliability benefits to the greater Twin Cities area. The presence of this 345 kV Project will electrically tie communities in the southwest metro to the larger metro region. (Ex. 104 at 8 (Alholinna Direct)).

2. *La Crosse Project*

a. *Rochester*

Reliability issues have arisen in the Rochester area due to a rapidly increasing population and an expanding economy. The population grew from 98,400 in 1985 to 131,400 in 2003, an increase of 34 percent. During that same time, peak electric load grew from 139 MW to 262 MW, an increase of 88 percent. And, in 2006, the peak load at the Rochester area substations reached 330 MW. (Ex. 94 at 5 (King Direct)).

Power to the Rochester area is supplied by three 161 kV lines, one from the west, Byron – Maple Lake 161 kV transmission line that connects the city to the Prairie Island – Bryon 345 kV transmission line; another from the northeast from the Alma Substation; and one from the south from the Adams Substation. The reliable maximum transmission capacity available to serve the Rochester area is 181 MW. To meet the larger demand for power, internal generation must be operated as system support. The local generation currently available includes 181 MW of generation at the Silver Lake and Cascade Creek stations, and two small hydro units on the Zumbro river. (Ex. 56 at 27 (Webb Direct); Ex. 94 at 4 (King Direct)).

Anytime the demand for electrical power exceeds 181 MW in the Rochester area, the failure of the Byron – Maple Leaf 161 kV line can cause service interruptions because the remaining transmission system can only reliably deliver 181 MW of power to Dairyland and RPU substations. RPU's ability to import power during certain contingencies is restricted by the "Rochester Area Import Prior Outage Standing Operating Guide" of the MISO, which requires RPU to use local generation when RPU's demand exceeds 145 MW to prepare for the next contingency. (Ex. 94 at 5 (King Direct)).

Consumer demand has already exceeded transmission system capacity (181 MW) and will soon exceed the capacity of the existing transmission system fully supported by area generation (362 MW). The substation forecast analysis, provided in Appendix C-1 of the Application, shows that this level will be exceeded in approximately 2011. (Ex. 94 at 6 (King Direct); Ex. 2 at Apx. C-1 (Forecasts)).

MISO independently confirmed the reliability issues confronting the Rochester area. MISO studied area reliability with all available generation assumed to be on. By 2011, MISO found numerous overloads resulting in a number of facility forced outages. (Ex. 56 at 27 (Webb Direct)). Further analysis indicated that the supply line from Alma may also experience overload conditions in the event that the other two supply line routes from Byron and Adams are out of service, even with all local generation in the area assumed available. (Ex. 56 at 28 (Webb Direct)).

The immediate load-serving need may be met by another set of 161 kV projects planned for the greater Rochester area. One of those projects is a set of three 161 kV lines recommended in the RIGO study: 1) a Pleasant Valley – Byron 161 kV line, 2) a Pleasant Valley – Willow Creek 161 kV line and 3) a Byron – Westside Energy Park ("WEP") 161 kV line (approximately 90 percent of this line would be double-circuited with the existing Byron – Maple Leaf – Cascade 161 kV line). Engineering analyses in the record suggest that the RIGO lines could alleviate certain limitations on the system in the area to allow for additional generation development in a wind-rich area of the State. Should the RIGO facilities be approved and constructed, the transmission system would be able to serve approximately 65 MW of additional load in the Rochester area for a total of 246 MW. With the addition of the 181 MW of local generation run for system support, the transmission system could meet the area's load serving until 2015. (Ex. 94 at 20 (King Direct)).

Neither the RIGO lines nor the Dairyland reconductor project eliminates the need for the La Crosse Project. If the RIGO lines and the reconductor project are constructed, the transmission system would be able to reliably serve approximately 468 MW in the Rochester area, a level expected to be reached in approximately 2018. (Ex. 94 at 21 (King Direct)). While this may address the urgency of the need for additional transmission in Southeastern Minnesota (from current 2011 to the end of the decade) it does not eliminate that need. To the contrary, an additional 345 kV connection in the Rochester area (along with the 161 kV lines) will provide a strong source that will serve customers in this fast-growing area reliably for decades. In any case, neither the RIGO lines nor the Dairyland reconductor project addresses the load-serving needs of the La Crosse/Winona area.

b. ***La Crosse, Winona, and Southeastern Minnesota***

The La Crosse/Winona area is also facing reliability issues as a result of increasing demand for electricity. (Ex. 94 at 10 (King Direct)). This area is served by four primary 161 kV transmission links or sources of power. (Ex. 56 at 29 (Webb Direct)). The capacity of the transmission system in this area is dependent on the operation of the power plants in the area: the Alma Generation Site (610 MW), the Genoa generator (368 MW), and the French Island Generation Plant (26 MW refuse burning and 140 MW of gas turbine peaking units). (Ex. 56 at 29 (Webb Direct); Ex. 94 at 9 (King Direct)). There are three critical contingencies that limit the capability of the system: 1) the Genoa-Coulee 161 kV contingency; 2) the Genoa off-line, Alma-Marshland 161 kV outage contingency; and 3) the John P. Madgett off-line, Genoa-Coulee 161 kV line contingency. (Ex. 94 at 10 (King Direct)).

- Regarding the Genoa-Coulee 161 kV contingency, in the event of the loss of this line, the La Crosse area system can reliably serve only 460 MW when generators at Alma and Genoa are running and the French Island, units 1 and 2 are running. In 2009, when two 60 MVAR capacitor banks are added to the La Crosse area, electrical system capability will be increased 10 MW to 470 MW. (Ex. 94 at 10-11 (King Direct)).
- Regarding the Alma-Marshland contingency, the Genoa-Lansing 161 kV line overloads once load reaches 430 MW. On July 17, 2006, the actual flows on the lines reached an all-time peak load of 447 MW. (Ex. 94 at 11 (King Direct)).
- Under the John P. Madgett-Genoa-Coulee contingency, in the event of the loss of the John P. Madgett ("JMP") generator and the Genoa – Coulee 161 kV, the system can reliably serve only 310 MW of customer demand. (Ex. 94 at 12 (King Direct)).

The forecast data shows the demand for power in the La Crosse/Winona area will exceed the 470 MW capacity of the transmission system in approximately 2009. By 2015, demand is estimated to reach 538 MW, exceeding the system's capability by 68 MW. (Ex. 94 at 12 (King Direct)). Until additional transmission facilities are installed, generators at French Island must be run for system support. MISO independently confirmed the reliability issues facing the La Crosse/Winona area. (Ex. 56 at 30 (Webb Direct))

c. ***Study Work***

There are three studies that led to proposing the La Crosse Project. The first two studies focused on localized solutions: the local Rochester study[32] and the local La Crosse/Winona study.[33] The third study, the Rochester/La Crosse Study, evaluated more regional system alternatives to address the load serving issues in both Rochester and La Crosse. (Ex. 94 at 13 (King Direct); Ex. 1 at Apx. A-2 (Rochester/ La Crosse Study)). Using the local studies as a starting point, the Rochester/La Crosse study identified a 345 kV regional solution. The best performing solution was the proposed 345 kV La Crosse Project. (Ex. 94 at 14 (King Direct)).

MISO's independent analysis confirmed the findings in the Rochester/La Crosse Study. For Rochester, MISO evaluated the following alternatives: uprating the existing 161 kV supply system, installing a second Byron transformer, and a new Byron to Northern Hills 161 kV line. These alternatives, however, did not address the community reliability issues. (Ex. 56 at 29 (Webb Direct)).

For La Crosse/Winona, MISO considered the effect of operating the only remaining generators in the area that were modeled off-line in the study. This alternative, however, would not relieve all of the overload conditions identified in the area for projected 2011 conditions. MISO also considered 161 kV rebuild option. Because each of the four supply routes are subject to overloading, this alternative

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[32] The local Rochester area load serving study considered four 161 kV options and 345 kV options to serve the growing demand in the Rochester area. The best performing and least cost option was a 345 kV transmission line from Byron to Pleasant Valley and eastward around Rochester. The study determined that, based on current load growth, that this solution would reliably serve the load until approximately the middle of the century. Ex. 94 at 13 (King Direct).

[33] The local La Crosse/Winona study screened 23 possible 161 kV alternatives to meet identified load serving needs and further evaluated the top five alternatives. Planning engineers concluded that even the best performing 161 kV option was inadequate to meet identified needs for several reasons, including the conclusions that in the long-run, a 345 kV transmission line would be required to serve the load and that a 345 kV solution would meet load serving needs for several decades longer with fewer transmission lines. Ex. 94 at 13-14 (King Direct).

would require a near complete rebuild of the local area system at an estimated cost of more than $173 million. This expenditure would not provide the level of support that is provided by the proposed project nor the ability to accommodate future load growth in the area to a comparable degree. (Ex. 56 at 13-23, 31 (Webb Direct)).

3. *Fargo Project*

a. ***St. Cloud***

The St. Cloud area, including Sauk Rapids and Waite Park, has experienced a 44% population increase from 1985 to 2005. The increase in demand for power that necessarily accompanies such a large population growth, has put the system at risk due to system limitations during a contingency. (Ex. 67 at 10 (Kline Direct)).

The St. Cloud area is served by five 115 kV transmission lines: Fischer Hill – Little Falls; Benton County – Granite City #1; Benton County – Granite City #2; Sherburne County – St. Cloud; and Wakefield – St. Cloud. The transmission system can be supported by the Granite City gas fired peaking plant, which has a 77 MW capacity. (Ex. 67 at 9 (Kline Direct)).

The critical contingency in the St. Cloud area is the loss of the double-circuit line between the Benton County Substation and the Granite City Substation during summer peak loading. The loss of this line results in the interruption of electrical power to customers served by the St. Regis Substation, and a limitation on the capacity of the transmission system to serve the remaining load. (Ex. 67 at 10 (Kline Direct)). The loss of the Benton County – Granite City double-circuit line also causes thermal overloads that must be mitigated by system operators. If system overloads remain after the system automatically drops the St. Regis load, system operators must cut service to customers until line loadings are back within normal range. Under this contingency, the transmission system can only meet the demand for 228 MW of load. (Ex. 67 at 10-11 (Kline Direct)). Another critical contingency is the loss of the

Crossroads – Granite City 115 kV line. It is projected that if this line were ever lost with load exceeding 430 MW, the St. Cloud – Sauk River 115 kV line would load to over 110 percent of its normal rating. (Ex. 67 at 11 (Kline Direct)).

MISO confirmed and identified additional reliability concerns facing the St. Cloud area. MISO analyzed a loss of both circuits at Benton County and Granite City, and confirmed the St. Regis load of 89 MW would automatically be isolated. Furthermore, the St Cloud – Sauk River line would overload to 133 percent of rating. MISO also identified low voltage occurrences on several 115 kV buses. (Ex. 56 at 24 (Webb Direct)). MISO projects that for 2011 summer peak conditions, the Wakefield – St. Cloud 115 kV line would overload by 42% and the Benton – St. Cloud by 8% of design rating, in the event of the loss of two Benton 230/115 kV transformers. Voltages at 18 115 kV buses would also be below design. (Ex. 56 at 25 (Webb Direct)).

b. *Alexandria Area/North Central Minnesota*

The Alexandria area is also facing reliability issues as a result of increasing demand for electricity and from a lack of sufficient bulk transmission supply facilities. (Ex. 67 at 7 (Kline Direct)). This area is served by three 115 kV transmission lines: Inman – Elmo, Douglas County – Long Prairie, and Grant County – Elbow Lake. (Ex. 56 at 20 (Webb Direct); Ex. 67 at 7 (Kline Direct)). The Alexandria area is also supported by a 7.8 MW generator located at the Alexandria Light and Power's Poleyard Substation. (Ex. 67 at 8 (Kline Direct)). There are several critical contingencies that jeopardize reliability in the Alexandria area. For instance, the loss of the Grant County – Elbow Lake 115 kV line results in low voltages when load reaches 171 MW. The area's peak load in 2006 was 157 MW, and 171 MW is the demand level anticipated by the winter of 2011 or 2012. It is necessary for the Alexandria area transmission system to be upgraded. (Ex. 67 at 8 (Kline Direct)).

MISO confirmed the reliability issues facing the Alexandria area by looking at the conditions in this area for projected 2011 winter peak conditions and for 2016 winter peak conditions. The analysis showed that for the modeled 2011 conditions there will be severe line overloads as high as 154% of design capability, and critically low voltages of 52% of design in this area for loss of two of the three 115 kV lines serving Alexandria. These conditions will deteriorate as load grows in the area beyond 2011. (Ex. 56 at 21 (Webb Direct)).

c. ***South Zone of the Red River Valley***

The South Zone of the Red River Valley has experienced population growth that has increased the demand for electricity. The population of the Fargo-Moorhead metropolitan area, the largest load center in the South Zone of the Red River Valley, has grown from 145,000 in 1985 to 187,000 in 2006, a 28.5% increase. (Ex. 1 at 1.9 (Application); Ex. 67 at 4 (Kline Direct)). The increasing population has resulted in increased demand for electricity in two ways. First, an increase in population means more new residential construction or greater use of electricity in already built homes. Second, increases in population generally go hand-in-hand with increases in commercial and industrial businesses. This increased demand has resulted in foreseeable conditions in which the existing transmission grid is inadequate either from a voltage or a thermal standpoint. (Ex. 67 at 4 (Kline Direct)).

Power to the South Zone of the Red River Valley is supplied by 15 high voltage transmission lines, the strongest of which is the Center-Jamestown-Maple River 345 kV transmission line. The remaining high voltage transmission lines in the area are 115 kV and 230 kV. The South Zone of the Red River Valley has limited local generation resources. There are eleven generators that collectively provide 250 MW of power. (Ex. 67 at 3 (Kline Direct)).

The critical contingency in this area is the loss of the Center – Jamestown portion of the Center-Jamestown-Maple River 345 kV line. (Ex. 1 at 1.10 (Application); Ex. 67 at 5 (Kline Direct)). When this portion is out, all load in eastern North Dakota must be served by the existing 230 kV network which cannot reliably support an additional transport sufficient power influx from generation-rich central North Dakota. The loss of the 345 kV line could also cause overloads on the Fargo – Sheyenne 230 kV line. As the system is configured, when load surpasses the critical level and contingencies occur, system operators will be forced to mitigate these overloads and voltage issues by interrupting service to customers. If the transmission system in this area is not improved, the area experiencing low voltage will continue to increase as load in the South Zone of the Red River Valley grows. The South Zone of the Red River Valley could exceed the electrical system capabilities in the 2016 to 2019 timeframe. (Ex. 67 at 5-6 (Kline Direct)).

The South Zone of the Red River Valley recently experienced outages to the Center-Jamestown segment. In 2005, the line was down for thirty-four hours as the result of a three-day snow and ice storm. In 2006, there were 17 outages of the Center-Jamestown section and in March 2007, there was an unplanned outage of this section. (Ex. 67 at 6 (Kline Direct)).

MISO independently analyzed the South Zone of the Red River Valley and confirmed there are numerous contingency conditions involving the forced outage of existing transmission facilities that will result in loadings on other existing facilities beyond their safe design capability. Additionally, other conditions will result in transmission level voltages below design criteria, and for certain conditions could result in voltage instability with resultant wide-area loss of load.

Specifically, MISO confirmed that the South Zone of the Red River Valley relies on power transported into the area on the Jamestown-Maple River 345 kV and other 230 kV lines in order to meet the majority of its load serving needs. The loss of the Jamestown – Maple River 345 kV along with one of the 230 kV lines could lead to an unstable decline in voltage in the region, with the potential for uncontrolled loss of large amounts of load across the region. (Ex. 56 at 18 (Webb Direct)). MISO also found that the Fargo 230 kV and 115 kV transformers will overload for the 2016 winter peak conditions, and under single contingency conditions the Mud Lake to Brainerd 115 kV line would overload, and six 115 kV substations would experience low voltage conditions. (Ex. 56 at 19 (Webb Direct)).

d. *Study Work*

Two formal transmission planning studies, the TIPS Report and the TIPS Update, have been undertaken over the past decade to evaluate the transmission system needs in the Red River Valley area. The TIPS Report recognized that the Red River Valley area experiences depressed system voltages during peak load conditions, making it vulnerable to voltage collapses. The TIPS Report looked at 30 alternatives. Planning engineers found that a 345 kV line from Maple River to Alexandria to Benton County provided voltage security, a generation source geographically diverse from the North Dakota generation, load serving support for the Alexandria and St. Cloud areas, and generally increased the capability of the transmission system to transfer power from North Dakota eastward.

In the 2006 TIPS Update, the Maple River to Alexandria to Benton County 345 kV line option was developed further into the project proposed in the Application. To get this endpoint, the TIPS Update analyzed four possible transmission sources: 1) a 230 kV line from Harvey to Prairie; 2) a second 230 kV line from Letellier through Drayton to Prairie; 3) a 230 kV from Boswell to Wilton; and 4) 345 kV line from Benton County to Alexandria to Maple River. (Ex. 1 Apx. A-3 (TIPS Update)).

The Benton County to Alexandria to Maple River option was determined to be the best option because it provided approximately 422 MW of incremental load-serving capability during first contingency conditions, and would increase access to generation capacity in western Minnesota, North Dakota and northern South Dakota. The TIPS Update also found that the Monticello Substation was an appropriate endpoint. This is because the Monticello termination provides additional reliability improvements in the event of an extreme system disturbance and will not require, from a routing perspective, a Mississippi River crossing.

In addition, MISO independently analyzed possible alternatives for the South Zone of the Red River Valley, Alexandria and St. Cloud areas and concluded the Fargo Project is the best option. (Ex. 56 at 17-26 (Webb Direct)). For the South Zone of the Red River Valley, MISO first considered the addition of voltage support equipment in the area such as capacitor banks. However, the South Zone of the Red River Valley area already has a very large amount of such voltage support devices. MISO also considered and rejected the addition of a second 230 kV line between the Boswell, Wilton and Winger substations.[34]

In the Alexandria area, MISO first studied redispatching of generation. This, however, was not a viable option since there is very little generation available in the area to support the load. The addition of capacitor banks in the Alexandria area was also ruled out as an alternative because such an approach would not materially reduce the line overload conditions expected, and would only minimally forestall the need for additional means of increasing the supply capability to the area. MISO also considered extending a 230 kV line but this did not provide the strength of support that the 345 kV proposals does. (Ex. 56 at 23-24 (Webb Direct)).

[34] This alternative was dismissed as the line addition would not be able to mitigate voltage collapse conditions as sufficiently as the Fargo Project. Furthermore, this alternative would not provide any relief to Alexandria and St. Cloud. MISO lastly considered new 345 kV line extensions from central North Dakota but such an alternative would involve the same or more miles as the Fargo Project, at similar costs, and would not provide necessary relief to the Alexandria and St. Cloud areas. Ex. 56 at 20 (Webb Direct).

Regarding St. Cloud, MISO analyzed deploying local generation. This option was ruled out because while there are four peaking plants into the Granite City Substation, even if all of these units were available and operating during a critical contingency, loading on the St. Cloud to Sauk River line segment would be 104% of rating. Reconductoring the overloaded line segments was considered, but the entire load in the area cannot be served without exceeding equipment ratings at 2011 projected load levels. (Ex. 56 at 25-26 (Webb Direct)).

4. *Brookings Project*

a. ***Southwestern Minnesota***

A significant benefit of the Brookings Project is improved regional reliability and increased generator outlet capability in the Buffalo Ridge region. (Ex. 104 at 7 (Alholinna Direct)). The Brookings Project will also provide improved reliability for local communities in the project area. The New Ulm and Redwood Falls area, Olivia and Bird Island areas, Granite Falls area, and the greater Twin Cities area will benefit from the installation of the Brookings Project. The New Ulm and Redwood Falls area will benefit from the presence of the Brookings Project because the new Franklin 345/115 kV transformer will provide a much needed new power supply point to the 115 kV system. The new Franklin transformer will also benefit the Olivia and Bird Island areas. The Hazel Creek – Lyon County 345 kV segment will strengthen the system's ability to serve the Granite Falls area and surrounding territory. (Ex. 104 at 7-8 (Alholinna Direct)). The Brookings Project will also electrically tie communities in the southwest metro to the larger metro region. (Ex. 104 at 8 (Alholinna Direct)).

MISO concurs that the Brookings Project will provide local reliability benefits to the area. Specifically, this project will support the underlying lower voltage transmission systems along the route with the installation of step-down transformers, which will reduce loadings on the 115 kV and 69 kV circuits extending into the project area from more distant supply sources by injecting a strong source of power at the step-down points along the route. Voltages on these systems will also be supported to provide for better service quality under contingent conditions involving local transmission systems. (Ex. 56 at 36 (Webb Direct)).

b. *Twin Cities Suburbs*

The Brookings Project will also provide community reliability benefits to the greater Twin Cities area. The presence of this 345 kV Project will electrically strengthen the larger metro region. This grouping extends from Hutchinson on the northwest, to Gaylord on the southwest, to Belle Plaine on the southeast, and Waconia on the northeast. (Ex. 104 at 8 (Alholinna Direct)).

In addition, Applicants' proposal includes a new 345 kV connection and a new 345/115 kV transformer at Lake Marion Substation that will provide significant load serving support in the surrounding growing communities in southern Dakota County. (Ex. 104 at 8 (Alholinna Direct)). Absent this 345 kV connection, it would be necessary to periodically build new 115 kV lines from the existing 345/115 kV substations on the north, southward through the already developed load area. *Id.* The presence of the Lake Marion Substation also defers the need for a reconductor of a transmission line between Mankato and Faribault (Ex. 1, Apx. A-4 at 37 ("EHV Study")).

c. *Study Work*

The EHV Study was undertaken to examine what transmission improvements could be made beyond the 825 MW facilities and the Buffalo Ridge Incremental Generation Outlet ("BRIGO") Projects to increase generation outlet capability in Southwestern Minnesota. The study started with a base plan of a single circuit 345 kV line from Brookings County Substations to the southwestern Twin Cities. The four primary options studied included: 1) the Base Plan, 2) Base Plan – Double-Circuit, 3) System Alternate, Brookings County to Blue Lake, and 4) System Alternative. (Ex. 1 at Apx. A-4 (EHV Study)).

As a result of the EHV Study, the Base Plan – Double-Circuit configuration[35] was selected as it was the best performing option. This configuration has the best results with regard to steady state and dynamic power system performance, prevention of inadvertent (loop) power flows, power transfer capability and power and energy losses, practicality, and price. In addition, the double-circuit in the Base Plan – Double-Circuit configuration increases power flow from the Buffalo Ridge area to the Twin Cities creating a more direct path for the power. This double-circuit option is expected to provide approximately 700 MW in additional outlet capability depending on the ultimate location of generators, 320 MW more than other options that do not have a double-circuited portion.

B. System Wide Growth

It has been decades since the electrical network serving Minnesota has been expanded to any large degree. Yet, during that same time the demand for power has continued to grow. As demand has grown, smaller (typically 69 kV and 115 kV) projects have been implemented. And as individual generators sought access to the system, transmission was deployed only to address the generator's needs, not to address long-term needs. In other words, "[t]ransmission planning in the U.S. has become primarily 'reactive,' in that investments are made in response to requests from customers." (Ex. 171 at 12 (Gramlich Direct)). This has resulted in a fairly uncoordinated development of smaller projects without a focus on the future.

[35] The Base Plan – Double-Circuit configuration is comprised of a single 345 kV circuit line from the Brookings County Substation to Lyon County. From Lyon County to Franklin and on to Helena, this configuration includes a double 345 kV circuit segment. This configuration also includes a 345 kV line from Lyon County to a new Hazel Creek Substation near Hazel Run and a 230 kV line between Hazel Creek and Minnesota Valley Substations near Granite Falls. Ex. 104 at. 11 (Alholinna Direct).

Rather than continue with this 'band aid' approach of addressing each individual issue as it surfaces, the CapX2020 utilities took a far more proactive and long-term approach.[36] A central mission of preparing the Vision Plan was to examine the overall systems of utilities serving Minnesota customers and the growth in demand for electricity anticipated in those systems by the year 2020. This coordinated approach allowed for the utilities to consider options that would provide for long-term needs while ensuring that near-term or immediate needs are addressed promptly.

There are generally three categories of transmission studies: Vision Studies, Mid-term Studies and Specific Studies. (Ex. 6 at 5 (Rogelstad Direct)). Vision Studies look at long-range needs and goals and are a high level, 50,000 foot, review of the electrical system; a blue print for the future with 10-to 25-year time horizon; and employ broad assumptions. (Ex. 6 at 5 (Rogelstad Direct) and Ex. 56 at 8 (Webb Direct)). Mid-term Studies are a mid-level, 25,000 foot, review of the electrical system; look at a seven to 15-year time horizon; and employ assumptions with more certainty. (Ex. 6 at 5 (Rogelstad Direct) and Ex. 56 at 8 (Webb Direct)). Specific Studies, including load-serving and interconnection studies are a shorter term, 5,000 foot, review of the electrical system; evaluate needs for specific circumstance; look at a one-to 10-year time horizon; and employ assumptions with more certainty. (Ex. 6 at 5 (Rogelstad Direct) and Ex. 56 at 8 (Webb Direct)).

The CapX2020 Vision Plan was initiated by the CapX2020 utilities to develop a long-term transmission plan to ensure that load in the region could be served reliably under different generation scenarios. It was intended to be a high level study to provide a blue-print for future development. (Ex. 6 at 11 (Rogelstad Direct)).

[36] "A proactive approach involves identifying future load needs and generation portfolios and assembling a transmission plan that meets future load with generation." Ex. 171 at 13 (Gramlich Direct).

1. *CapX2020 Vision Plan Forecasts*

In preparing the Vision Plan, the CapX2020 utilities required a forecast of future system demand to calculate overall system growth between the period 2009-2020. Compiling readily-available forecast data, two scenarios for expected load growth increases between 2009 and 2020 were developed: a 6,300 MW level and a more conservative level one-third lower, 4,500 MW. (Ex. 48 at 4 (Lacey Direct)). The higher level was estimated based on forecasted demand requirements of those systems in the Vision Plan study area,[37] including Integrated Resource Plan ("IRP") data and Load and Capability Report data. (Ex. 48 at 5 (Lacey Direct)). The lower level was chosen to conservatively assess system needs if demand growth is lower.

The calculated load level for 2009 was 20,201 MW. (Ex. 48 at 4-5 (Lacey Direct)). Next, forecasted growth rates were applied to each balancing authority's area's electrical power demand. This data gathering and analysis resulted in the Vision Plan forecast of nearly 26,500 MW by 2020 or several thousand megawatts of growth between 2009 and 2020. (Ex. 48 at 5 (Lacey Direct)). The "slow growth" forecast scenario, approximately 30 percent lower, was merely a check or validation of the planning effort to assess system needs under conditions substantially different than the base planning assumptions. (Ex. 48 at 5 (Lacey Direct)).

2. *Applicants Verified Demand Forecasts*

In preparing the Application, Applicants compared the Vision Plan forecasts with more recent forecasts developed from two other available sources of data: Integrated Resource Plans and MAPP Load and Capability Reports. Applicants aggregated the forecasts of utilities Integrated Resource Plans and MAPP Capability Reports and compared those aggregated forecasts to the Vision Plan forecasts. This

[37] The study region selected for the Vision Plan was primarily based on the geographic boundaries of the service territories of utilities with customers in Minnesota. Those systems include all of Minnesota and portions of North Dakota, South Dakota, Iowa, Wisconsin, and Upper Michigan.

analysis confirmed that several thousand megawatts of demand growth can be expected to occur between 2009 and 2020. (Ex. 48 at 7-8 (Lacey Direct)).

The Integrated Resource Plan and Load and Capability data indicate a range in demand growth from 2009 to 2020 from 4,095 MW to 5,186 MW. (Ex. 48 at 8 (Lacey Direct)). These numbers were further adjusted during discovery and were presented into the record as Exhibit 51 (Applicant 1st Supp. Response to NAWO/ILSR Information Request No. 7). The compilation of Mr. Lacey's analysis and adjustments is set forth below in updated figure 6.6 from the Application. This data shows expected load growth in the 3,900 or higher MW range. (Exhibit 53 at 8 (Lacey Rebuttal)).

Updated Figure 6-6*

Forecast Source	Citation	Forecast Scenario	Load Forecast (MW)		Load Growth by 2020 (MW)
			2009	2020	
CapX2020 Vision Plan	Rogelstad (15:2-4)	Expected Growth	20,201	26,488	6,287
	Lacey (8:15-16)	Slow Growth**	20,201	24,701	4,500
MAPP Load and Capability	Application Figure 6-6	System Demand	20,783	25,969	5,186
Integrated Resource Plans	Lacey (8:15-16)	High	22,488	27,392	4,904
		Median	21,332	25,427	4,095
IRP per NAWO/ILSR IR No. 7***	Michaud (4:20-21)	High	22,938	27,708	4,789
	NAWO IR No. 7	Medium	21,789	25,708	3,919
OES Analysis	Ham (15:2-8)	Base Case	22,228	27,060	4,832+
[Footnotes omitted]					

This data show demand growth in the several thousand megawatt range. No other party (except OES) provided any forecasting data; nor did they prepare their own forecasts. While some parties speculated about the potential for lower growth in the future, no credible evidence was put forward to call this conclusion into question.

Even if the forecasts are further adjusted to take into account isolated issues it would make no difference. No party submitted evidence that demand growth would be less than 2,000 MW. And the uncontroverted testimony in this record is that demand growth as low as 2,000 MW would still justify these transmission lines on the basis of regional reliability. (Rogelstad 2b Vol. 83-84).

3. ***OES Verification of Applicants' Demand Forecasts***

OES is the only other party who conducted any analysis of Applicants' demand forecasts. While OES used different methodologies and made adjustments based on its interpretation of a number of State policies, OES likewise concluded that demand growth in the several-thousand-megawatt range will occur from 2009-2020.

Mr. Ham, first obtained the most recent load growth data from the Midwest Reliability Organization ("MRO") 2007 Series summer peak model which showed 22,228 MW peak demand in 2009. (Ex. 257 at 15 (Ham Direct)). Mr. Ham then used a growth rate based on the most recently approved Integrated Resource Plan from Minnesota utilities to obtain year 2020 summer peak demand. (Ex. 257 at 15 (Ham Direct)). The resulting forecast showed that year 2020 peak demand as 27,060 MW, which is about 572 MW greater than Applicants' original forecast of 26,488 MW. (Ex. 257 at 15 (Ham Direct)).

Mr. Ham further concluded that capacity needs were particularly significant during the 2010-2015 timeframe. He reviewed recently approved Integrated Resource Plans from four investor-owned utilities: Xcel Energy, Minnesota Power, Otter Tail, and Interstate Power and Light Company,[38] that operate in Minnesota. (Ex. 257 at 9 (Ham Direct)). OES concluded that these four utilities showed the likelihood of "significant capacity and energy needs during the 2010- 2015 timeframe." (Ex. 257 at 9 (Ham Direct)). Also, Great River Energy filed its Integrated Resource Plan in 2005 and showed "significant capacity and energy need during the same timeframe." (Ex. 257 at 9 (Ham Direct)). Given that the five utilities examined serve most customers in the State and all of them are likely to need capacity and energy during 2010-2015 timeframe, OES concluded that "the State needs more capacity and energy during the 2010-2015 timeframe." (Ex. 257 at 9 (Ham Direct)).

[38] Docket No. E002/RP-04-1752; Docket No. E015/RP-04-865; Docket No. E017/RP-05-968; Docket No. E001/RP-05-2029 (respectively).

4. *System Growth-Solutions*

The Vision Plan found that without the addition of significant transmission improvements, the State and the surrounding region would experience numerous transmission overloads, outages, and voltage problems as load continues to grow. Planning engineers consulted with generation planners, developers, and other stakeholders on their predictions of the distribution of generation, planning engineers decided to test potential solutions using varying generation distribution solutions.

The 345 kV Projects that Applicants propose, along with the Bemidji Project, were common to all scenarios. This means that the 345 kV Projects are needed whether overall demand growth is higher or lower than the forecasts in this record. While it may be argued that FUTURE projects could be deferred or delayed by slowing growth in demand, it is not true that the CURRENT projects are impacted by changes in the forecasts.

5. *Generation Outlet*

To serve the growing energy demands of consumers in this State, large amounts of new electric generation, both renewable and nonrenewable, will need to be installed. (Ex. 1 at 1.2-1.4 (Application)). OES calculated (in Mr. Ham's revised calculations) the need for 4,621– 6,817 MW of new generation by 2020 to meet overall customer usage by 2020, including 1,269 – 2,094 MW of non-renewable energy generation and 3,160– 4,927 MW of new wind to meet state RES. (Ex. 274 at 2 (Ham Surrebuttal) and Ex. 275 (Revised Interconnection Need Table)).

The demand for renewable generation resources is driven by the 2007 legislative enactment, Minn. Stat. § 216B.1691 ("RES Statute"). The RES Statute requires Xcel Energy to supply 30% of its retail energy in Minnesota from renewable energy sources by 2030 (with interim milestones). Other electric utilities must supply 25% of retail energy in Minnesota from renewable energy sources by 2025 (with interim milestones). OES's Susan Peirce calculated that Minnesota utilities need an additional 3,148 MW to 4,911 MW of wind generation to meet the RES Statute. (Ex. 247 at 4 (Peirce Surrebuttal)). In addition, Minnesota Transmission Owners, including Applicants, recently provided the Commission with an RES Report that indicated that 5,000 to 6,000 MW of new renewable energy will be needed to meet the RES requirements. (Ex. 54 at 290 (Renewable Energy Standards Report 2007, filed November 1, 2007 in Docket No. E999/M-07-1028 ("RES Report"))). Additional transmission will be required so the network can deliver these megawatts of new renewable generation to Minnesota customers. (Ex. 1 at 1.14 (Application)).

The 345 kV Projects are a necessary step toward meeting Minnesota's generation support needs. The Brookings Project will increase generation support in the Buffalo Ridge area. The working assumption is that this project will provide an additional approximately 700 MW of outlet from the Buffalo Ridge. (Ex. 104 at 5 (Alholinna Direct)). This number assumes injections at six specific locations and it could be different when final locations are established. (Alders 13 Vol. 154). While the Brookings Project has not been dedicated to renewable energy, its outlet capacity will be in the Buffalo Ridge where considerable interest in wind-energy exists.

The Fargo Project also has the potential of advancing renewable generation development by expanding interconnection opportunities for generation development in northwest Minnesota and eastern North Dakota. (Ex. 1 at 6.49 (Application)). Currently, transmission outlet capability from North Dakota is limited, in part, by the NDEX interface.[39] The Fargo Project increases transfer capability across the NDEX by approximately 350 MW. This could support additional outlet for generators in northwest Minnesota and eastern North Dakota. (Ex. 67 at 12 (Kline Direct)).

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[39] The electrical boundary between Minnesota and North Dakota is identified by the Department of Energy as a congested area that limits generation development. Ex. 1 at 6.49 (Application).

The La Crosse Project has not been analyzed to determine a specific amount of generation support. However, this line provides transmission support to the south and east and will become part of the network that serve as the bulk transport system that will allow all forms of generation development to continue such that the energy needs of this State will be met. (Ex. 1 at 1.15 (Application)).

Minnesota is a net importer of electricity.[40] This simply means that Minnesota cannot produce all of the electricity that it consumes and must have the ability to import electricity from other states. (Ex. 257 at 5 (Ham Direct)). As participants in the MISO energy market, Applicants have the right to buy low-cost energy from the wider region and import it to Minnesota, provided there is adequate transmission available to transport the electricity from its remote source to Minnesota. (Ex. 257 at 4 (Ham Direct)). High voltage connections to neighboring states will enhance the ability to import low-cost generation from the MISO market. (Ex. 257 at 4 (Ham Direct)).

C. Summary of Project Timing and Costs

While actual in-service dates and costs will vary depending on a variety of factors, such as availability of crews and material, final route selection, weather and other contingencies, the following chart summarizes the record on these points:

[40] According to the U.S. Department of Energy, Energy Information Administration, Minnesota imported 16 percent of its electricity through interstate transmission in 2006. Ex. 257 at 5 (Ham Direct).

PROJECT	APPROXIMATE COST	APPROXIMATE IN-SERVICE DATES	RIGHT-OF - WAY WIDTHS	STRUCTURE HEIGHTS	AVERAGE SPANS
La Crosse Project	$389-$415 (Alma Crossing)[41] $407 -$432 (La Crescent and Winona Crossings)[42]	North Rochester to La Crosse 345 kV: 2015 Hampton to North Rochester 345 kV: 2015 North Rochester to Chester 161 kV: 2015 Northern Hills to North Rochester 161 kV: 2011 (if RIGO does not go forward) Northern Hills to North Rochester 161 kV: 2012 (if RIGO goes forward) [43]	150-foot wide right-of-way (345 kV)[44] 80-foot wide right-of-way (161 kV)[45]	130- 175 feet tall (345 kV double-circuit structures)[46] 70-105 feet tall (161 single circuit structures)[47]	750-1,100 feet (345 kV)[48] 600-900 feet (161 kV)[49]
Fargo Project	$500-$640[50]	Monticello to St. Cloud: 2011 St. Cloud to Alexandria: 2013 Alexandria to Fargo: 2015[51]	150-foot wide right-of-way[52]	130- 175 feet tall (345 kV double-circuit structures)[53]	750-1,100 feet (345 kV)[54]

[41] Ex. 89 at 4 (Stevenson Surrebuttal).

[42] Ex. 88 at 4 (Stevenson Surrebuttal).

[43] Ex. 83 at 9 (Stevenson Direct).

[44] Ex. 83 at 9 (Stevenson Direct).

[45] Ex. 83 at 9 (Stevenson Direct).

[46] Ex. 1 at 2.10 (Application).

[47] Ex. 1 at 2.11 (Application).

[48] Ex. 1 at 2.10 (Application).

[49] Ex. 1 at 2.11 (Application).

[50] Ex. 88 at 5 (Stevenson Rebuttal).

[51] Ex. 83 at 16 (Stevenson Direct).

[52] Ex. 83 at 14 (Stevenson Direct).

[53] Ex. 1 at 2.10 (Application).

[54] Ex. 1 at 2.10 (Application).

Brookings Project	$650-$725 million[55]	Lyon County to Helena: 2012 Helena to Hampton Corner: 2013 Brookings County to Lyon County: 2013[56]	150-foot wide right-of-way[57]	130- 175 feet tall (345 kV double-circuit structures)[58]	750-1,100 feet[59]
Underlying System Improvements	$70-$100 million[60]				

VII. APPLICATION OF RELEVANT CRITERIA

A. The Statutes and Rules

1. *Minn. Stat. § 216B.243, subd. 3*

The primary statute that applies to whether Certificates of Need should be granted is Minn. Stat. § 216B.243, subd. 3. This statute lays out the overall obligation on Applicants and provides a road map for the ALJ to make determinations in this case. The statute first requires the Commission to consider whether energy conservation could eliminate the need for the requested facility. The statute then identifies twelve factors for the Commission to consider in determining whether the applicant has justified its claimed need:

> (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;
>
> (2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;

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55 Ex. 120 at 4-5 (Lennon Rebuttal).

56 Ex. 116 at 8 (Lennon Direct).

57 Ex. 116 at 7 (Lennon Direct).

58 Ex. 1 at 2.10 (Application).

59 Ex. 116 at 8 (Lennon Direct).

60 Ex. 1 at 2.17 (Application).

(3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;

(4) promotional activities that may have given rise to the demand for this facility;

(5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;

(7) the policies, rules, and regulations of other state and federal agencies and local governments;

(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;

(9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a; and

> (12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with risk.[61]

2. *Other Statutory Criteria*

There are five other statutes that establish criteria for a Certificate of Need determination:

- Minn. Stat. § 216.2422, subd. 4 and 216B.243, subd. 3a (renewable energy preference);
- Minn. Stat. § 216B.2426 (distributed generation);
- Minn. Stat. § 216B.1691 (RES); and
- Minn. Stat. § 216B.1612 (C-BED); and
- Minn. Stat. § 216H.03 (carbon).

Minn. Stat. § 216B.243, subd. 3a provides two additional criteria for the Commission to consider in the appropriate case when a proposed facility transmits electric power generated by means of a nonrenewable energy source. Minn. Stat. § 216B.2422, subd. 4 imposes requirement similar to § 216B.243, subd. 3a.

Minnesota Statutes § 216B.2426 requires that distributed generation be "considered" as follows:

> The Commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.[62]

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[61] Subfactor (12) is not applicable because Applicants are not proposing a nonrenewable generating plant.

[62] Minnesota Statutes § 216B.169, subd. 1(c) defines distributed generation as "a distributed generation facility of no more than ten megawatts of interconnected capacity that is certified by the commissioner under subdivision 3 as a high-efficiency, low-emissions facility."

Minn. Stat. § 216B.2426.

Minnesota Statutes § 216B.1691 sets forth the following RES obligations for State utilities. This statute generally requires Xcel Energy to obtain 30% of its retail energy sales from renewable sources by 2020 and all other Minnesota utilities to achieve 25% retail renewable energy sales by 2025. The RES Statute further provides milestones to ensure steady progress toward the statute's goals. The statute provides:

> Each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated: 1) 2012 – 12 percent; 2) 2016 – 17 percent; 3) 2020 – 20 percent; and 4) 2025 – 25 percent.[63]

Minn. Stat. § 216B.1691, subd. 2a(a). Minnesota Statutes § 216B.1612 requires the following for C-BED:

> A utility subject to section 216B.1691 that needs to construct new generation, or purchase the output from new generation, as part of its plan to satisfy its good faith objective and standard under that section must take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements, applying standard reliability criteria, to fulfill some or all of the identified need at minimal impact to customer rates.

Minn. Stat. § 216B.1612, subd. 5.

3. *Minn. R. 7849.0120 Criteria*

Minn. R. 7849.0120 establish criteria mirroring the criteria established by Minn. Stat. § 216B.243, subd. 3. The Commission must evaluate "the factors listed under each of the [rule] criteria" "to the extent that the Commission considers them

[63] For Xcel Energy, the requirements are as follows: 1) 2010 – 15 percent; 2) 2012 – 18 percent; 3) 2016 – 25 percent; and 4) 2020 – 30 percent. Minn. Stat. § 216B.1691, subd. 2a(b).

applicable and pertinent to a facility proposed[.]" Minn. R. 7849.0100. The Commission must make a written finding as to each criterion. *Id.*

The four rule factors, together with their subfactors, which are set forth in Minn. R. 7849.0120, are:

> A. the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states, considering:
>
> (1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;
>
> (2) the effects of the applicant's existing or expected conservation programs and state and federal conservation programs;
>
> (3) the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974;
>
> (4) the ability of current facilities and planned facilities not requiring Certificates of Need to meet the future demand; and
>
> (5) the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources;
>
> (B) a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering:
>
> (1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
>
> (2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;
>
> (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and

(4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;

(C) by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health, considering:

(1) the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs;

(2) the effects of the proposed facility, or a suitable modification thereof, upon the natural and socioeconomic environments compared to the effects of not building the facility;

(3) the effects of the proposed facility, or a suitable modification thereof, in inducing future development; and

(4) the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality; and

(D) the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

B. <u>Application of the Criteria</u>

To be granted Certificates of Need, Applicants must satisfy the requirements of both the statutes and rules. As noted above, in many respects the statutory criteria and the Commission's rules are essentially the same. Since the Commission must make a written finding regarding each of the rule criteria, Minn. R. 7849.0100, Applicants have organized their analysis by first focusing on the rules and whether the 345 kV Projects satisfy the rule criteria. To the extent that the statutory criteria differ, these statutory criteria are separately analyzed.

1. ***Future Adequacy, Reliability, or Efficiency of Energy Supply***

a. ***<u>Accuracy of the Demand Forecast</u>***

Minn. R. 7849.0120(A) requires consideration of "the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility" when determining if denial of a Certificate of Need application would have an adverse effect.

As discussed above, as part of the Vision Plan, Applicants evaluated regional transmission needs under two peak demand growth forecasts. This analysis indicated a growth of several thousand megawatts of demand between 2009 and 2020. (Ex. 48 at 5 (Lacey Direct)). Further analysis by Applicants confirmed a growth of at least 3,900 MW. (Ex. 53 at 8 (Lacey Rebuttal)). OES likewise found a growth level of 4,621 MW to 6,817 MW. (Ex. 275 at 2 (Revised Interconnection Need Table)). With regard to the specific load centers, Applicants also provided substation demand forecasts for each of the communities at risk that demonstrated the timing of the need in each area. (Ex. 2 at Apx. C-1-C-5 (Forecasts)). Mr. Ham, independently verified Applicants' forecast and concluded it was reasonable. (Ex. 257 at p. 14-15 (Ham Direct)). No other party provided expert testimony disputing Mr. Ham's conclusion.

2. ***Effects of Conservation Programs***

The Minnesota legislature established the important energy policy of encouraging cost-effective conservation by mandating an analysis of conservation in a Certificate of Need proceeding. Two provisions of Minnesota Statutes §216B.243 expressly require such a showing.

First Minn. Stat. § 216B.243, subd. 3 states:

> No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load management.

Second, Minnesota Statutes § 216B.243, subd. 3(8) provides in relevant part that determining need requires the Commission to evaluate whether cost-effective conservation measures can reasonably be expected to obviate the need for some or all of the claimed energy need. The Commission, in assessing need, shall consider:

> [A]ny feasible combination of energy conservation improvements, required under section 216B.241, that can . . . (i) replace part of all of the energy to be provided by the proposed facility, and (ii) compete with it economically.

Minn. Stat. § 216B.243, subd. 3(8). Thus, under subdivision 3(8), Minnesota law requires an assessment of whether all or part of the energy Applicants claim needs to be transmitted over the requested transmission lines can be replaced by energy conservation. These statutory requirements are reflected in the second subfactor of Minn. R. 7849.0120A(2), which requires consideration of Applicant's conservation programs and state and federal conservation programs.

As required by the Commission's Exemption Order, Applicants provided their respective resource plan filings, the Commission's orders in those respective proceedings, and summaries of the filings and the Commission's orders. Based upon this information, OES determined Applicants' conservation programs and state and federal programs do not obviate the need for the 345 kV Projects.

Specifically, OES determined that conservation efforts will not reduce or obviate the need for the 345 kV Projects to address community service reliability, system wide growth, and outlet capacity because the effect of conservation will not appreciably reduce the projected growth in peak electric demand.

- As it pertains to community service reliability, OES determined that forecasted load for Rochester, La Crosse/Winona, the southern Red River Valley and St. Cloud will still exceed critical load levels by 2011 or earlier, even after taking into account the impacts of 1.5% energy savings goal for Conservation.[64]

[64] Minn. Stat. § 216B.242, subd. 1C.

Alexandria will exceed critical load levels by the 2015-2020 timeframe even after taking into account the 1.5% energy savings goal. (Ex. 215 at 13, 15 and 16 (Davis Direct)).

- For system wide growth, Applicants forecasted growth of several thousand megawatts between 2009 and 2020. Even when this number was reduced (Ex. 53 at 8 (Lacey Rebuttal Updated Table 6-6)) to take into account recent resource plan filings and reductions due to conservation, the low end system wide growth figure still approaches 4,000.

- As required by the 2007 CIP legislation, OES calculated that Conservation may decrease Applicants projected peak demand growth by approximately 700 MW (1.0% energy savings) to 1,400 MW (1.5% energy savings). (Ex. 215 at 12-13 (Davis Direct)). Importantly, OES concluded that the 345 kV Projects are needed even with these reductions in projected demand growth. (Ex. 307 at 34 (Rakow Surrebuttal)).

- For outlet capacity, OES calculated Minnesota utilities have an overall generation interconnection need of 4,600 MW or more by 2020 to serve Minnesota utility customers reliably. (Ex. 271 at 17 (Ham Direct Errata)). In addition, OES determined a need for 3,000-5,000 MW of transmission capability to meet the RES. (Ex. 231 at 26 (Peirce Direct); Ex. 215 at 12-13 (Davis Direct)). While Conservation may reduce the forecasted peak demand, the benefits of Conservation are outweighed by the need for approximately 3,000 to almost 5,000 MW of transmission capacity. (Ex. 231 at 26 (Peirce Direct); Ex. 215 at 12-13 (Davis Direct)).

3. *Effects of Promotional Practices*

Minn. R. 7849.0120(A)(3) requires consideration of "the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974." This subfactor is concerned with the impact of Applicants' promotional practices. Applicants promotional activities did not cause an increase in energy demand necessitating the 345 kV Projects. (Ex. 1 at 1.20-1.21 (Application) and *See* Ex. 282 at 85 (Rakow Direct)).

4. *Facilities Not Requiring Certificates of Need to Meet Demand*

Minn. R. 7849.0120(A)(4) requires consideration of "the ability of current facilities and planned facilities not requiring Certificates of Need to meet the future demand." This subfactor assesses the ability of facilities that would not require a Certificate of Need to meet future demand.[65] This criterion calls for consideration of both transmission and generation as potentially eliminating the need for the Certificates of Need. Each of these options will be considered in turn.

a. *Non-Certificate of Need Transmission*

The record establishes that transmission facilities that do not require Certificates of Need (including reconductoring and adding equipment at existing substations) are not capable of addressing all of the (i) community service reliability, (ii) system wide growth and (iii) generation outlet, needs that will be addressed by the 345 kV Projects.

- **La Crosse Project**: non-Certificate of Need transmission projects, such as additional rebuilding and reconductoring of existing lines, will not satisfy the need to meet system wide growth and increase generator support and will only address community reliability concerns for the short-term. (Ex. 282 at 29-30 (Rakow Direct) and Ex. 1 at 7.24 (Application)). For example, the reconductoring of the Adams – Rochester and Rochester – Wabaco – Alma 161 kV lines, would increase Rochester area community service reliability sufficient to meet anticipated load for only five or six years. Afterwards, new transmission lines would be required. (Ex. 1 at 7.24 (Application)).

- **Fargo Project**: non-Certificate of Need transmission projects, such as rebuilding and reconductoring existing facilities, will not satisfy the three needs. (Ex. 282 at 29-30 (Rakow Direct). For example, MRES considered a short-term solution involving the addition of capacitor banks and breakers projected to address local needs until 2012. (Ex. 1 at 7.24 (Application)). But ultimately,

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[65] Under Minn. Stat. § 216B.2421 there are two types of facilities that could meet future demand yet not require a Certificate of Need: 1) transmission lines a) less than 100 kV, b) between 100 kV and 200 kV but less than 10 miles long and not crossing a state border, or c) above 200 kV but less than 1,500 feet long; and 2) generation facilities less than 50 MW.

the addition of capacitor banks and breakers will require the construction of new transmission as load continues to grow and voltage continues to decrease. (Ex. 1 at 7.24 (Application)).

- **Brookings Project**: non-Certificate of Need projects, such as additional rebuilding and reconductoring of existing lines, will not satisfy the need to increase generation outlet from southwestern Minnesota and South Dakota. (Ex. 282 at 29-30 (Rakow Direct) and Ex. 1 at 7.25 (Application)). Reconductoring is also not an option because it would overload several existing lines. (Ex. 282 at 29-30 (Rakow Direct)). Considering the potential magnitude of additional wind generation from the Buffalo Ridge, it is not possible to achieve satisfactory thermal and dynamic stability performance of the regional system without the addition of bulk power transmission facilities. (Ex. 1 at 7.25 (Application)). Rebuilding and reconductoring also would not meet regional reliability needs nor provide the community load serving benefits the proposed project will provide.

b. ***Non-Certificate of Need Generation***

There is insufficient evidence to consider generation as an alternative as required by Minn. R. 7849.0110. Generation, such as peaking generation and distributed generation including C-BED, cannot address all of the needs – community service reliability, regional reliability, and generation outlet – that will be addressed by the 345 kV Projects and, as a result, is not an alternative to the 345 kV Projects. [66] (Ex. 9 at. 3-5 (Rogelstad Rebuttal)).

(1) Community Service Reliability Need

Generation (whether renewable or non-renewable) is not an alternative in the record for addressing community service reliability needs. Indeed, generation could not be a viable alternative to meet the three needs here. First, generation is not as reliable as transmission system improvements. Transmission lines have the ability to operate more than 99 percent of the time. This reliability level is one of the benefits of constructing transmission lines. In comparison, the most reliable generation

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[66] Another reason why generation is not an alternative is that it is more costly than projects like the 345 kV Projects. (Ex. 1 at 7.14-7.15 (Application)).

facilities are only available 93 percent of the time. For generation to serve as a realistic alternative for transmission infrastructure, it should reasonably have the same reliability as the proposed transmission facilities. Typically, this means three units equal to the size of the deficiency must be installed, which can be very costly. Second, if generators were installed, they could not be easily expanded in the future as demand for power grows. In contrast, transmission infrastructure can be increased by reconductoring, increasing the voltage or adding new lines. Third, if generation is added without additional transmission infrastructure, the resulting power cannot be transmitted outside of the local area. In other words, when generators are capable of producing more power than is being used, that power cannot be transmitted onto the grid to be used elsewhere. (Ex. 9 at 3-5 (Rogelstad Rebuttal)).

C-BED projects are ill-suited to meet community service reliability needs. Most C-BED proposals are for wind-energy projects, which provide energy on a variable basis. The transmission system needs to be designed to deliver energy reliably during all hours of the year and under all conditions to ensure that adequate power can be delivered to customers even if the wind is not blowing or if the wind is blowing at maximum efficiency. As a result, adding C-BED generation to the system will not address the reliability concerns. (Ex. 6 at 35 (Rogelstad Direct)).

NAWO/ILSR speculated that DRG and other small generation could address some community service reliability concern. (Ex. 140 at 37-38 (Michaud Direct)). But no analysis was provided to support this speculation. Thus, DRG and other small generators are not an alternative on the record that could be considered under Minn. R. 7849.0110.

(2) Regional Reliability

The need to bolster overall transmission system reliability likewise cannot be satisfied by installing additional local generation without transmission. Local generation does not have the same reliability characteristics as transmission and cannot be used to meet this need. On the other hand, by constructing additional 345 kV transmission lines, the regional system is benefited as a whole because those additional connections provide for a more robust system that will be better able to withstand system contingencies. (Ex. 9 at 3-5 (Rogelstad Rebuttal)).

(3) Generation

The third need, generation support, particularly in southwestern Minnesota, by definition, cannot be met by new generation. (Ex. 282 at 28 (Rakow Direct); Ex. 9 at 3-5 (Rogelstad Rebuttal)).

5. *Making efficient use of resources*

Minn. R. 7849.0120(A)(5) requires consideration of "the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources." Evaluating the fifth subfactor involves assessing whether the proposal makes appropriate use of existing resources. The 345 kV Projects will make appropriate use of existing resources. (*See* Ex. 5 (Environmental Report)).

C. <u>No More Reasonable and Prudent Alternative to Upsizing Alternative</u>

1. *No Alternatives Offered Into Record*

The second rule factor is Minn. R. 7849.0120 B which states:

> A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record . . . .

Minn. R. 7849.0120 B lists four specific subfactors for consideration in determining whether a more reasonable and prudent alternative has been established.

These four subfactors include: (1) the appropriateness of the size, type, and timing of the proposed facility compared to those of reasonable alternatives; (2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives; (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and (4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives. Minn. R. 7849.0120 B.

This rule is written so as to place the burden of production and persuasion on the party seeking to advance an alternative. Minn. R. 7849.0120 B. In making its decision, the ALJ and the Commission "shall consider" only those alternatives for which "there exists substantial evidence on the record with respect to each of the criteria listed in part 7849.0120." Minn. R. 7849.0110. This rule requires opponents of the proposed 345 kV Projects to come forward and establish the existence and characteristic of a more reasonable and prudent alternative.[67]

2. ***No Reasonable Alternatives Available***

Applicants' proposals (both the main proposal and the Upsizing Alternative) are the only reasonable and prudent alternatives in the record.[68] Based on this record, the ALJ must find that there is no reasonable and prudent alternative to the proposed 345 kV Projects. Nevertheless, as part of the Application process, Applicants considered and analyzed the following alternatives:

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[67] "Under the certificate of need process established by statute and rule, an applicant bears the burden of proving the need for a proposed facility. An applicant fails to meet this burden when another party demonstrates that there is a more reasonable and prudent alternative to the facility proposed by the applicant. Minn. Stat. § 216B.243, subd. 3; Minn. R. 7851.0120, subp. 8. This regulatory scheme is simply a practical way to prevent the issuance of a certificate of need when there is a more reasonable and prudent alternative to the proposed facility without requiring the applicant to face the extraordinary difficulty of proving that there is not a more reasonable and prudent alternative." *In the Matter of the Application of the City of Hutchinson for a Certificate of Need to Construct a Large Natural Gas Pipeline*, 2003 WL 22234703 at * 7; *see also* George A. Beck, MINNESOTA ADMINISTRATIVE PROCEDURE, § 10.3.1 (2d ed. 1998); *Peterson v. Mpls. St. Ry.*, 31 N.W.2d 905, 909 (1948) (burden of producing sufficient evidence on specific issues).

[68] OES proposed a 500 kV alternative to the Fargo Project and MCEA proposed a double-circuit 345 kV configuration alternative to the Fargo Project. Ex. 282 at 78 and 82 (Rakow Direct); Ex. 177 at 23 (Schedin Direct). Both parties, however, abandoned those alternatives in favor of Applicants' proposal. Ex. 307 at 35 (Rakow Surrebuttal); Ex. 199 at 5 (Schedin Surrebuttal).

- Alternative System configuration:
  - -Upgrade existing lines;
  - -Higher voltages;
  - -Lower voltages; and
  - -Alternative substations
- Double-circuiting
- Generation:
  - -Local peaking generation;
  - -Renewable generation;
  - -Distributed generation; and
  - -Community based generation;
- DC Lines
- Underground construction
- No build

(Ex. 1 at Ch. 7 (Application)). In addition, each of the three project-specific studies (Rochester/La Crosse Study; TIPS Update; and EHV Study) all included numerous options and alternatives in the analyses in order to confirm that the proposed transmission project was the most appropriate alternative available.[69]

a. *System Upgrades*

As discussed above, Applicants concluded the needs identified could not be met by existing facility upgrades alone, including reconductoring and by adding equipment at existing substations. (Ex. 1 at 7.24 (Application)).

b. *Double-Circuiting*

As opposed to the Upsizing Alternative that provides the capability to add a second transmission circuit to the structures in the future, Applicants studied double-circuiting for all three transmission projects but decided at this time it was only appropriate for certain segments of the Brookings Project. (Ex. 121 at 11 (Grivna Rebuttal); Ex. 177 at 19-21 (Schedin Direct)). This is warranted for this project to

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[69] *See* Ex. 1 at Apx. A-2 at 17-36 for the Rochester/La Crosse Study alternative analysis; Ex. 1 Apx. A-3 at p.19-50 for the TIPS Update alternative analysis; and Ex. 1 at Apx. A-4 at 7-41 for the EHV Study alternative analysis.

increase the power flow from the Buffalo Ridge area to the Twin Cities. The double-circuit segments create a more direct path for power due to a decreased impedance of the double-circuit configuration and thus minimize the amount of inadvertent flow to other areas of the transmission system and reduce losses.

The Upsizing Alternative provides the POTENTIAL for double-circuiting the remaining segments in the future, depending upon how circumstances unfold. This is a far better outcome than double-circuiting these lines today. Applicants' proposed approach better matches cost with future need and provides significant flexibility to address future circumstances, whatever they may be.

c. ***Generation***

As discussed above and below, Applicants concluded that generation, regardless of the size or fuel source, is not a viable alternative to the 345 kV Projects. Generation is not as reliable and is less cost-effective than the 345 kV Projects. (Ex. 1 at 7.12-7.23 (Application)).

d. ***DC Lines***

As discussed below, Applicants concluded that AC lines will be more cost-effective in addressing the identified three needs. (Ex. 1 at 7.25-7.26 (Application)).

e. ***Underground Construction***

The availability of an underground alternative was considered for the 345 kV Projects. (Ex. 1 at 7.27 (Application)). Generally, for transmission voltages (115 kV or greater) overhead construction is the preferred technology due to costs. (Ex. 1 at 7.27 (Application)). Underground transmission lines also have substantially longer construction times and longer repair times than equivalent overhead lines. (Ex. 1 at 7.27 (Application)). Underground facilities are not well-suited for lengthy, high voltage transmission lines, such as those proposed here. (Ex. 1 at 7.27 (Application)).

f. ***No Build***

The no build alternative was also considered and found to be unreasonable. If the 345 kV Projects are not approved, there will be no improvement in the electric service reliability in the communities at risk, additional generation development on the Buffalo Ridge will be prevented, and existing facilities will have to operate at their present levels. (Ex. 1 at 7.36 (Application)).

3. *Size, Type, and Timing of the Proposed 345 kV Projects*

Minn. R. 7849.0120 B(1) states that the Commission is to consider "the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives."

a. ***Size Analysis***

The "size" analysis refers to the quantity of power transfers that the transmission infrastructure improvements enables. (Ex. 282 at 14 (Rakow Direct)). In designing the proposed 345 kV Projects, Applicants examined both higher voltage lines and lower voltage lines.

(1) Higher Voltages

Higher voltage lines, such as 500 kV or 765 kV transmission lines, could be used to provide high capacity transmission power, but have several limitations with respect to the needs identified by Applicants. Higher voltage lines physically can accommodate higher flows of electricity over those lines but the flow on these higher voltage lines would be limited to what can reliably be carried on the surrounding high voltage transmission system. The current high voltage transmission system around the Twin Cities consists of double-circuit 345 kV lines with 345 kV line connections in other parts of the State. The neighboring states, which are electrically interconnected to Minnesota and supply large amounts of power to Minnesota, also operate 345 kV systems. The existing transmission system, in conjunction with the higher voltage additions, would not be able to withstand the outage of a 500 kV or 765 kV line because the redistributed flows would create overload conditions.

Higher voltage lines would also not be appropriate to meet the particular needs identified for the three individual projects.

- With regard to the Fargo Project, construction of a 500 kV line would mean that there are fewer intermediate stops along the line. (Ex. 67 at 16 (Kline Direct); Ex. 1 at 7.4 (Application)). This would result in diminished community service reliability benefit of this line and cause this line to become almost entirely a generation outlet facility. (Ex. 67 at 16 (Kline Direct); Ex. 1 at 7.4 (Application)). The Northwest Exploratory Study, a MISO-sponsored study in which a consortium of Upper Midwest utilities participated, concluded that the system provided no better service when 500 kV lines were constructed instead of 345 kV lines. (Ex. 67 at 16 (Kline Direct); Ex. 1 at 7.4 (Application)).
- A similar analysis would apply to the La Crosse Project. The existing transmission system in and around southeastern Minnesota includes 161 kV and 345 kV facilities. (Ex. 94 at 23-24 (King Direct); Ex. 1 at 7.4 (Application)). Expanding that existing system with a double-circuit compatible 345 kV transmission line takes advantage of the existing infrastructure and provides a logical method for serving expanding customer needs in that area. (Ex. 94 at 23-24 (King Direct); Ex. 121 at 40-43 (Grivna Rebuttal), Ex. 1 at 7.4 (Application)).
- Higher voltages were also considered for the Brookings Project. Planning engineers designed the 345 kV solution to provide significant additional generation outlet capability in a manner compatible with the existing transmission system for a reasonable cost. (Ex. 104 at 16 (Alholinna Direct)). Applicants are aware that MISO is currently in the early stages of studying the feasibility of a series of 765 kV lines to provide outlet for large amounts of wind generation. (Ex. 1 at 7.4 (Application)). If these proposed 765 kV lines are constructed, the Brookings Project will provide a foundation for these higher voltage lines to be more easily integrated into the transmission system. (Ex. 104 at 17 (Alholinna Direct)).

(2) Lower Voltages

Lower voltages, such as 161 kV and 115 kV lines, were also evaluated. The lower voltages were determined not to be a reasonable alternative in a majority of situations because they cannot provide efficient transfer capability over the long distance required to satisfy all of the needs identified by Applicants. Lower voltage lines result in higher losses that reduce the efficiency and desirability of this alternative. Lower voltage lines were also found to be inadequate for the long-term community service reliability needs sought to be addressed.

- Lower voltages were evaluated for the Fargo Project in the TIPS Update that concluded that none of the lower voltage options were adequate to address all of the needs identified in the study. (Ex. 67 at 17 (Kline Direct); Ex. 1 at 7.6 (Application)). For instance, in the St. Cloud area, planning engineers determined that a new 345 kV source on the western side of the St. Cloud region would provide the desired load serving benefit. (Ex. 67 at 17 (Kline Direct); Ex. 1 at 7.6 (Application)).
- Lower voltage options were also rejected for the La Crosse Project. In Rochester, lines lower than 161 kV were not considered because the load serving lines in the Rochester area are primarily 161 kV. (Ex. 94 at 24 (King Direct)). The proposed 161 kV facilities will integrate well into the existing standard transmission voltage in the Rochester area. (Ex. 94 at 24 (King Direct)). Lower voltages such as 115 kV were not considered a reasonable alternative because the voltage is not adequate to serve the forecasted load and could create new transmission constraints in the Rochester area. (Ex. 94 at 24 (King Direct)). A voltage lower than 345 kV was not considered for the Minnesota/Wisconsin connection of the La Crosse line because it was determined to be an inadequate bulk power source to the Rochester community. (Ex. 94 at 24 (King Direct)). To address Rochester's long-term community service reliability needs, Rochester needs a new 345 kV source in addition to the existing Prairie Island 345 kV source. (Ex. 94 at 24 (King Direct)).
- For the Brookings Project, utilizing lower voltages would not result in the desired increase in generation outlet, thereby foregoing the benefit of additional wind generation from southwestern Minnesota and other points west. (Ex. 1 at 7.7 (Application)).

OES agreed that Applicants' proposed size is reasonable. (Ex. 282 at 20 (Rakow Direct)). MCEA similarly agreed that the size proposed by Applicants was appropriate. (Ex. 199 at 5 (Schedin Surrebuttal)). No other party provided expert testimony disputing Applicants' proposed size.

b. ***Type Analysis***

The "type" analysis refers to the transformer nominal voltages, rated capacity, and nature (AC or DC) of power transported. (Ex. 282 at 14 (Rakow Direct)).

(1) Type of Conductors Appropriate

Applicants propose to use bundled conductor 954 ACSS cables for the 345 kV transmission lines and single conductor 795 ACSS cable for the 161 kV transmission lines. (Ex. 282 at 21 (Rakow Direct)). Generally, for the 345 kV lines, the bundled conductor 954 ACSS cable was selected for its characteristics of lower losses with slightly higher cost at higher loadings. (Ex. 282 at 21 (Rakow Direct)). For the 161 kV lines, the proposed conductor is necessary to provide system support in the event of a 345 kV line outage. (Ex. 282 at 21 (Rakow Direct)).

OES concluded that Applicants' proposed conductors are reasonable. (Ex. 282 at 22 (Rakow Direct)). No other party provided expert testimony disputing Applicants' proposed choice of conductors.

(2) AC Line Appropriate

Applicants considered the alternative of a DC line over the selected AC line. (Ex. 1 at 7.25 (Application); Ex. 282 at 22 (Rakow Direct)). DC transmission lines normally consist of two current-carrying conductors instead of the three associated with an AC configuration. (Ex. 1 at 7.25 (Application)). A DC transmission line's primary intended purpose is to deliver electricity from a distant generation location (several hundred miles away) to a load center. (Ex. 1 at 7.26 (Application)). Such lines do not have the capability to provide load serving to an AC system because there are no intermediate substation connections. (Ex. 1 at 7.26 (Application)).

A DC transmission line is also not an economically viable alternative. The total cost of a DC system becomes equal to an AC system at about 300 miles of untapped line length due primarily to reduced losses on DC transmission. (Ex. 1 at 7.26 (Application)). However, the advantages of long distance transmission capability and slightly lower line costs are countered by the increased expense of converting AC to DC or DC to AC at the end of each line as well as any intermediate substation. (Ex. 1 at 7.26 (Application)). Here, the number of substations that the proposed transmission lines must connect with makes the DC configuration cost-prohibitive. (Ex. 282 at 23 (Rakow Direct)). The incremental cost increase of the DC conversion on each line is estimated to be approximately $9.7 billion (2,055 MVA * 14 terminals). (Ex. 1 at 7.26 (Application)).

Given this significant incremental cost increase, OES concluded Applicants' proposed AC configuration is reasonable. (Ex. 282 at 23 (Rakow Direct)). No other party provided expert testimony disputing Applicants' proposed AC Line.

c. *Timing*

The "timing" analysis refers to the on-line date for the transmission infrastructure improvements. (Ex. 282 at 14 (Rakow Direct)). Applicants' proposed timing for the proposed 345 kV Projects, assuming the permitting processes (Minnesota route permits, Wisconsin CPCN, *etc.*) are completed by end of 2010, is described below.

La Crosse Project Schedule	
North Rochester – North La Crosse 345 kV segment	2015
Hampton – North Rochester 345 kV segment	2015
North Rochester – Chester 161 kV segment	2015[70]

(Ex. 83 at 9 (Stevenson Direct)). OES examined this proposed schedule and found that it was reasonable. (Ex. 282 at 24 (Rakow Direct)).

Fargo Project Schedule	
Monticello – St. Cloud 345 kV segment	2011
St. Cloud – Alexandria 345 kV segment	2013
Alexandria – Fargo 345 kV segment	2015

(Ex. 83 at 16 (Stevenson Direct)). OES examined this proposed schedule and found it to be reasonable. (Ex. 282 at 24 (Rakow Direct)).

Brookings Project Schedule	
Lyon County – Helena 345 kV segment	2012
Helena – Hampton Corner 345 kV segment	2013
Brookings County – Lyon County 345 kV segment	2013

(Ex. 116 at 8 (Lennon Direct)). OES examined this proposed schedule and found it to be reasonable. (Ex. 282 at 25 (Rakow Direct)).

These schedules, however, are conceptual, based on information known as of the date of this filing and are based upon planning assumptions that balance the

[70] Applicants request the flexibility to construct the Northern Hills – North Rochester 161 kV line on an accelerated schedule, *i.e.*, by third quarter 2011, if the RIGO projects do not go forward. Ex. 83 at 9 (Stevenson Direct).

timing of implementation with the availability of crews, material and other practical considerations. As a result, these schedules may be subject to adjustment and revision. No other party provided expert testimony disputing Applicants' proposed timing for the 345 kV Projects.

C. Protecting the Natural and Socioeconomic Environments

The third factor is Minn. R. 7849.0120 C which states:

> By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the neutral and socioeconomic environments, including human health.

This rule factor lists four specific subfactors including: (1) an analysis of the relationship of the proposed 345 kV Projects to overall state energy needs, (2) its effect on the natural and socioeconomic environments; (3) induced development and (4) the socially beneficial uses of the output. Minn. R. 7849.0120 C(1)-(4).

1. *Relationship to Overall State Energy Needs*

Evaluating the first subfactor, Minn. R. 7849.0120 C(1), concerns assessing the relationship of the 345 kV Projects to overall state energy needs. Overall, the demand for energy in Minnesota is growing and, in particular, during the 2010-2015 timeframe. (Ex. 257 at 9 (Ham Direct)). The 345 kV Projects will have a positive impact on meeting the State's energy needs by providing transmission to deliver and to import energy generated or purchased to meet the State's energy needs. (Ex. 257 at 10 (Ham Direct)). As a result, the 345 kV Projects will have a positive impact on the ability of the transmission system to meet the overall state energy needs.

2. *Effects on the Natural and Socioeconomic Environments*

The second subfactor, Minn. R. 7849.0120 C(2), concerns assessing the impacts on the natural and socioeconomic environments of the proposed 345 kV Projects compared to the no build alternative. Applicants have satisfied this subfactor because the deleterious impact of the no build alternative outweighs the Projects' impacts on the natural and socioeconomic environments.

The 345 kV Projects will have short-term, minimal or remediable impacts on the natural environment, and positive short-term impacts on the socio-economic environment. There are, however, no known irremediable environmental issues associated with the proposed configuration that would preclude construction of the proposed facilities. (Ex. 128 at 6 (Rasmussen Direct); Ex. 1 at 8.1 (Application)). Indeed, OES determined, in the Environmental Report, that the proposed projects would have no significant, permanent impacts on the socioeconomic and natural environments. (*See generally*, Ex. 5 (Environmental Report)).

While the no build alternative would not result in impacts to the natural environment, the potential for present and future transmission problems relating to community service reliability issues would persist, the existing transmission network will not be able to accommodate the forecasted total system wide growth of several thousand megawatts of new demand, added generation and renewable energy support would be diminished, and risk of outages during peak-demand periods would likely increase across Minnesota. OES stated in the Environmental Report:

> This alternative does not address the voltage support issues that are being experienced in areas throughout Minnesota; it is likely that there would be an unacceptable negative effect on residents and local economies due to unreliable electrical services; and progress towards the state's RES might be significantly impeded.

(Ex. 5 at 80 (Environmental Report)).

3. *Effects in Inducing Future Development*

The third subfactor, Minn. R. 7849.0120 C(3), concerns assessing the effects of the proposed facility in inducing future development. The 345 kV Projects will not induce future development. Rather the projects are necessary to address three needs -

community service reliability, system wide growth and generation outlet - which will support future development that is already forecasted to occur in Minnesota. OES notes in the Environmental Report that without the 345 kV Projects "it is likely that there would be an unacceptable negative effect on residents and local economies due to unreliable electrical services . . . and progress towards the state's RES might be significantly impeded." (Ex. 5 at 80 (Environmental Report)). The 345 kV Projects will not create or induce development but will provide the infrastructure necessary for such development to occur.

4. *Socially Beneficial Uses of the Output*

The fourth subfactor, Minn. Rule 7849.0120 C(4), requires an assessment of the socially beneficial uses of the proposed 345 kV Projects including its uses to protect or enhance environmental quality. The output of a transmission line is the transportation of electricity from one location to another location.

The outputs of the 345 kV Projects will provide socially beneficial uses. Specifically, the 345 kV Projects will provide service reliability benefits to communities throughout the State and region, will strengthen the transmission network to meet several thousand megawatts of additional demand for electrical power in Minnesota and surrounding states, and will add increments of transmission capacity to the network to support the continuing development of new generation, including renewable energy generation.

D. <u>Compliance with Relevant Policies, Rules, and Regulations</u>

Minn. R. 7849.0120 D provides:

> The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

This rule addresses whether there is reason to conclude at this time that the proposed Projects would fail to comply with the regulations of other governmental agencies.

Applicants have committed to comply with all relevant policies, rules, and regulations of other state and federal agencies and local governments applicable to the construction and operation of the 345 kV Projects, and there is no evidence in the record that Applicants could not or would not comply with any applicable requirements of other state and federal agencies and local governments.

E. Other Statutory Requirements

1. *Renewable Energy Preference Statutes*

a. *Description of Statutes*

Regarding renewable energy preference, there are two sections of Minnesota Statutes that refer to Certificates of Need, Minnesota Statutes §§ 216B.243, subd. 3a and 216B.2422, subd. 4. These renewable energy preference statutes are not applicable to the present proceeding.

Section § 216B.243, subd. 3a establishes two additional criteria for the Commission to consider when a proposed facility transmits electric power generated by means of a nonrenewable energy source. Specifically, in circumstances where this statute applies, an applicant must show it has:

> (1) explored the possibility of generating power by means of a renewable energy sources; and
>
> (2) demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source.

Minn. Stat. § 216B.243, subd. 3a.[71]

[71] For purposes of Minnesota Statutes § 216B.243, subd. 3(a), "renewable energy source" includes hydro, wind, solar, and geothermal energy and use of trees or other vegetation as fuel.

Minn. Stat. § 216B.2422, subd. 4 provides substantially the same requirements in the generation context. This statute provides:

> The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B. 243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a renewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.

Minn. Stat. § 216B.2422, subd. 4.

b. ***Application of Statutes***

Neither of these renewable energy preference statutes affect the outcome of this proceeding. First, transmission facilities are not "renewable" or "nonrenewable" but rather provide delivery for electricity to customers on a non-discriminatory and open-access basis. Thus, application of these statutes is questionable at best.

Second, Section 216B.243, subd. 3a, has been found by the Commission to only to apply when a transmission facility transmits electric power generated by means of a nonrenewable energy source. For example, the Commission found this statute applicable when considering the transmission necessary to connect the Big Stone II coal-fired generating facility. (Ex. 1 at 7.16 (Application)). Similarly Minn. Stat. § 216B.2422, subd. 4 is applicable to new or refurbished "nonrenewable energy facilit[ies]."

As explained by Dr. Rakow, these renewable preference statutes do not establish additional standards in the current Certificates of Need proceeding because the 345 kV projects are not proposed to and will not interconnect to any particular generation resource. (Ex. 282 at 12 (Rakow Direct)). Rather, the 345 kV Projects are proposed to address three needs: community service reliability, system-wide growth and generation outlet. (Ex. 282 at 11-12 (Rakow Direct)).

The Commission has previously found that the renewable generation preference statutes, such as Minn. Stat. § 216B.243, subd. 3a, are no bar to granting Certificates of Need for transmission lines where the proposed transmission line does not immediately interconnect to a new generation source and will not interconnect with a specific generation source. *In the Matter of the Application of Otter Tail Power Company for Certificate of Need for Appleton-Canby 115 kV High Voltage Transmission Line, Order Granting Certificate of Need*, Docket No. E-017/CN-06-677, p. 9 (April 18, 2007). (Ex. 27 (Order)). The 345 kV Projects will not immediately interconnect to a new generation source or a specific generation source. (Ex. 282 at 12 (Rakow Direct)). Furthermore, to the extent that upgrading the transmission system in an area improves the overall ability of the system to transmit renewable energy into the transmission grid, it provides an independent benefit that is consistent with the statutory preference. (Ex. 1 at 7.16 (Application)).

There is no dispute on this record that the transmission facilities proposed in this case are intended for general system support. Essentially the Commission has found that renewable energy preference statutes apply to transmission only in the circumstance where the transmission is intended to interconnect or accommodate a specific and known generating source.[72] That is not the situation here and Sections 216B.2422, subd. 4 and 216B.243, subd. 3a should be held not to apply to this situation.

In any event, these renewable preference statutes are easily satisfied. The 345 kV Projects will transmit renewable energy within the State. The RES Report illustrates that these lines will improve the overall ability of the system to transmit renewable energy into the grid. The RES Report "requires utilities to report on

[72] *See* ALJ Supplemental Findings of Fact, Conclusions of Law, and Recommendations at 11, *In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota,* Docket No. E-017/CN-06-677, p. 11 (April 18, 2007).

specific transmission line proposals that are necessary to meet the intermediate RES milestones." On the Fargo Project, the RES Report notes that:

> Because the line crosses the traditional boundary for determining North Dakota generation export ("NDEX"), installation of the line will mean a likely increase in the amount of generation that can be transferred from North Dakota and northwestern Minnesota to the Twin Cities.

(Ex. 54 at 297 (RES Report)).

The RES Report also outlines the importance of the Brookings Project in meeting the RES goals:

> Another crucial part of meeting the RES milestones is an increase in generation outlet from the Buffalo Ridge Area…A large portion of this line is proposed to be constructed as a double-circuit 345 kV line in order to increase generation outlet as much as possible.

(Ex. 54 at 298 (RES Report)). Both projects will serve the purpose of improving the system's overall ability to transmit energy from a region that has significant renewable generation potential. Both of these lines provide system reliability benefits that will enhance the ability of energy sources to access the grid. Thus, the renewable generation preference has been satisfied. (Ex. 1 at 7.17 (Application)).

2. *Carbon Moratorium Under Minn. Stat. § 216H.03*

Minnesota Statute 216H.03, subd. 3 provides that:

> No person shall (1) construct within the state a new large energy facility that would contribute to statewide power sector carbon dioxide emissions; (2) import or commit to import from outside the state power from a new large energy facility that would contribute to statewide power sector carbon dioxide emissions; or (3) enter into a new long-term power purchase agreement[73] that would increase statewide power sector carbon dioxide emissions.

[73] "Long-term power purchase agreement means an agreement to purchase 50 megawatts of capacity or more for a term exceeding five years." Minn. Stat. 216H.03, subd. 3 (3).

Minn. Stat. § 216H.03 is satisfied because the 345 kV Projects are not proposed to interconnect with any particular generation resource. (Ex. 282 at 12 (Rakow Direct)). These lines will serve three needs: 1) community service reliability, 2) system wide growth, and 3) generation outlet. (Ex. 282 at 12 (Rakow Direct)).

Moreover, the 345 kV Projects will not contribute to Minnesota's power sector carbon dioxide emissions because the lines do not generate or emit carbon. In addition, these particular lines are not proposed to interconnect to any particular carbon-emitting generator. Further, any future carbon-emitting generator will need to obtain permits in its own right and its emissions will be judged at the time those permits are sought.

Dr. Rakow confirmed that the 345 kV Projects will not contribute to an increase in State-wide carbon dioxide emissions. He testified that "I found no evidence to show that Applicants intend to access any particular (renewable or nonrenewable) resource with the proposed transmission line, much less a baseload coal plant." Thus, there is no evidence in this record that the proposed transmission lines are intended for any particular generation, including carbon emitting generation.

Mr. Ham concurred with Dr. Rakow's analysis, stating that it is unlikely that any new coal plants will be built:

> [S]everal major financial institution already declare that, without any carbon dioxide sequestrations, basically they aren't financing any coal power plant. So how any utility can finance those wanting to build coal power plant nowadays is very expensive and to build and sell those energy to the market.

(Ham 24 Vol. 66-69). Accordingly, Minn. Stat. § 216H does not preclude construction of the facilities.

F. Consumer Cost Impact

Applicants recognize that, given the size of the proposed 345 kV Projects, utility customers are interested in their potential cost impact. As required by the Commission's Order Designating Applicants and Setting Filing Requirements (June 4, 2007), Applicants provided a cost impact analysis in Appendix D-5 of the Application. (Ex. 2 at Apx. D-5 (Ratepayer Impact)). This analysis identifies the approximate annual revenue requirement for each CapX2020 345 kV project based on assumed ownership shares, allocates these costs among MISO pricing zones, forecasts each CapX2020 345 kV project's owner's charges for each applicable MISO pricing zone, and summarizes the projected total annual charges to each of the owners of each CapX2020 345 kV project. (Ex. 137 at 2-3 (Grover Direct)).

Dr. Rakow took Applicants' analysis and calculated a net consumer cost impact. (Rakow 24 Vol. 122). His cost impact analysis is found in Exhibit 310, a copy of which is appended to this Brief as Attachment F. In short, an average residential customer should see retail utility net cost impact averaging $1.47 per month.

VIII. CONDITIONS

OES proposed reporting and other procedural conditions. Applicants accept those conditions and have included them in the accompanying Proposed Findings. Other parties propose substantive conditions that are not justified on this record. NAWO/ILSR argue that Applicants be required to acquire 600 MW from DRG projects. MCEA argues that the firm transmission capacity from these lines be 'locked up' exclusively for wind generation.

A. DRG/C-BED Conditions Inappropriate

NAWO/ILSR assert that Applicants be required to obtain 600 MW of DRG (and/or C-BED) resources as a condition to any Certificates of Need.

(NAWO/ILSR 10 Vol. 44:9-11 ("Part of our case has to do with a condition for 600 megawatts and this goes to that.") NAWO/ILSRs' condition, however, is based upon an incorrect understanding of the requirements for transmission Certificates of Need, is unsupported by the record, and is inconsistent with the results of the DRG Study (upon which NAWO/ILSR place great reliance). As Dr. Rakow explained:

> [NAWO/ILSR] proposed a generation condition which conflicts with the nature of this proceeding. This is a proceeding to evaluate the proposed need for transmission to deliver additional generation and reliability. The DRG Study itself clearly indicates that it does not contain data of sufficient quality to order specific projects or even generic projects at the specific sites since the detailed interconnection studies and the overall cost-effectiveness of generation projects at the proposed sites was not established. Viewed as a transmission issue, the DRG [Study] only speaks to 600 MW and provides no information on any other potential interconnection capacity. For the 600 MW the DRG Study indicates that further work is necessary. Relying on potential interconnection capacity that is not confirmed at this time does not reasonably meet the need identified in the record in this case.
>
> No action from the Commission is appropriate in part because there is not adequate foundation for Michaud's condition. Further action is not necessary because this potential capacity on the existing transmission system exists or does not exist irrespective of the Commission's decision in this proceeding.

(Ex. 308 at 1-2 (Rakow Statement)). Applicants support Dr. Rakow's analysis.

1. *DRG Does Not Address Needs*

The Phase I DRG Study, (Ex. 110) concluded there are DRG sites where a cumulative 600 MW of new generation could be added to the existing transmission system without significantly affecting any transmission infrastructure. (Ex. 109 at 4-6 (Alholinna Surrebuttal)). That study, however, is unrelated to the current proceeding and does not provide a basis for denying or conditioning the Certificates of Need. Mr. Alholinna explains why the DRG Study does not address the three claimed needs:

> The CapX2020 transmission lines are needed for each of the three reasons set forth in our Application. At most the DRG study addresses a portion of providing capacity and outlet for new generation. Applicants agree that dispersed renewable generation is one component in meeting Minnesota's RES requirements. However, the 600 MW of dispersed generation identified in Phase I of the DRG study is only 10 and 20 percent of the renewable energy resources that will be required for the utilities to meet these renewable requirements. Plus 600 MW of largely wind-energy generation will only be a small fraction of the capacity needed to address system growth by 4,000-6,000 MW of system growth that will be needed to meet the energy needs of the state by the year 2020.

(Ex. 109 at 6-7 (Alholinna Surrebuttal)).

2. *No DRG-Based Alternative*

Second, there is no DRG-based alternative in the record and the Phase I DRG Study does not create an alternative for consideration. (Ex. 307 at 32 (Rakow Surrebuttal) ("such generation would only be an alternative if it addressed all of Applicants' claimed needs")). Minn. R. 7849.0120, subp. 2 requires the party seeking to advance an alternative to provide the necessary data. By not advancing a DRG-based alternative, NAWO/ILSR have not carried their burden. Minn. R. 7849.0110.

3. *Phase I DRG Study Misinterpreted*

Third, NAWO/ILSR incorrectly interpret the Phase I DRG Study, misunderstand the study's analysis, and exaggerate its conclusions when they claim that the DRG Study found that 600 MW of dispersed generation projects <u>could be installed</u> in Minnesota without building any new transmission lines. (Ex. 154 at 23 (Michaud Surrebuttal)). As Dr. Rakow explained these assertions are unfounded. (*See* Ex. 308 at 1 (Rakow Statement)) Mr. Schedin also testified that NAWO/ILSR overstated the analysis and findings of the Phase I DRG Study. The DRG Study results are intended to serve as a general guide for locations for up to 600 MW of new

DRG, but each project must be studied in detail via the local utility for system impacts. (Ex. 199 at 15 (Schedin Surrebuttal)).

Mr. Alholinna confirmed NAWO/ILSRs' misunderstanding of the DRG Study: "My primary disagreement is, is that more than 600 could be placed on the system. And especially when we were talking about phase one in a 2010 time frame." (Alholinna 11 Vol. 67). "[A]s I responded to some of the cross-examination that I do believe that 600 megawatts is an upper limit." (Alholinna 11 Vol. 68). Finally, "it is my opinion that this [DRG study] does not change the need certainly for these CapX group one projects that Applicants have proposed." (Alholinna 11 Vol. 70)

4. *Transmission Supports DRG Development*

In fact, the record demonstrates that the 345 kV Projects are needed to support the widespread development of DRG facilities. As explained by Mr. Alholinna, the Phase I DRG Study actually demonstrated that the addition of DRG facilities would constrain the transmission system. "[T]here were just a number of facilities that, under contingency analysis that became overloaded." (Alholinna 10 Vol. 86-87). In other words, building additional transmission will assist in developing DRG facilities.[74] MCEA witness Robert Gramlich concurred. "The DRG Study found that a large share of the potential dispersed generation sites could not be developed because of constraints on the high-voltage electric grid. . . . Thus the constraints on the high-voltage electric grid seriously limit the potential deployment of all types of renewable generation, both dispersed and larger-scale." (Ex. 176 at 2-3 (Gramlich Surrebuttal)). "The expansion of the high-voltage transmission grid proposed

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[74] "Q: Is it possible that additional transmission of some kind would be need to be built in order to provide support for dispersed renewable generation in the amount of 600 megawatts you propose? A: Yes, it is possible, and it has only been demonstrated for the specific 20 sites in the study that you could do 600 megawatts without building transmission. So it possible that you might need some lower-voltage infrastructure to support different locations." Michaud 16 Vol. 104: 5-15.

through the CapX project is a critical step for increasing the use of all types of renewable energy." (Ex. 176 at 4-5 (Gramlich Surrebuttal)).

B. MCEA's Conditions Inappropriate

MCEA's requested conditions are substantially similar to those conditions imposed in the Certificate of Need proceeding for the 825 MW of wind energy outlet capacity from Southwestern Minnesota (Docket No. E-002/CN-01-1958 (the "825 MW Wind Outlet Proceeding"). Specifically, MCEA requested the following six conditions, as modified in Exhibit 213, be imposed on Applicants:

> 1. Applicants contractually commit to acquire wind-energy generation resources that utilize the capacity enabled by the new transmission lines at least two years prior to the expected in-service date. Applicants shall seek Commission approval so that the Commission can grant approval of the commitments within six months after execution.
>
> 2. Inform the Commission within 30 days of obtaining Certificates of Need on how Applicants propose to allocate the new transmission capacity.
>
> 3. Sign PPAs or committing to utility-owned renewable energy projects within the timeframe of the Minnesota RES milestones, or earlier.
>
> 4. Make transmission service requests with MISO for the total amount of new transmission capacity associated with the three lines as appropriate to ensure full subscription of such capacity for renewable generation.
>
> 5. Designate the acquisitions commitments as Network Resources pursuant to the MISO tariffs, Module B, III, Section 30 no later than 10 days after the Commission approves PPAs and/or the commitment to construct utility-owned renewable resources.
>
> 6. Report on any federal issues that affect these conditions.

(Ex. 213 (("MCEA Conditions")). MCEA's Conditions should be rejected for several reasons.

1. ***Distinguishable from Prior Proceeding***

The MCEA Conditions are very similar to those imposed in the 825 MW Wind Outlet Proceeding.[75] In that proceeding, the Commission granted Certificates of Need for transmission facilities in Southwestern Minnesota specifically and solely to provide additional generator outlet capacity to serve wind generation in that region. But, as recognized by OES, "the need case made by Applicants in this docket, is <u>fundamentally different</u> than the need case made by Xcel [Energy] six years ago." (Ex. 303 at 6 (Rakow Rebuttal) (emphasis added)). And, therefore, even OES does not find that the Conditions are appropriate in this instance

The only need found in the 825 MW Wind Outlet Proceeding was "supporting the development of renewable energy, and conditions furthering that end were necessary to satisfy that that claimed need."[76] (Ex. 303 at 6 (Rakow Rebuttal)). Here, three separate needs – community service reliability, system-wide growth, and generation outlet – have been established. (*See* Ex. 282 at 9 (Rakow Direct)).

Imposing conditions focused on only one subset of one of these three needs, (locking up <u>generation outlet</u> only for renewable generation) elevates this subcategory above all the other considerations. Such a narrow approach is "unreasonable." (Ex. 303 at 7 (Rakow Rebuttal)). In this case, Applicants' established needs are not limited only to renewable energy sources or to any particular region. (Ex. 132 at 9 (Alders Rebuttal)). And, unlike the 825 MW Wind Outlet Proceeding, the fuel type for new generation has not been limited. (Ex. 132 at 9 (Alders Rebuttal)).

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75 "Q: Am I correct, Mr. Ellison, that you designed these conditions essentially to operate in the same manner as the conditions that were proposed and imposed in the 825 megawatt case? A: There are some differences reflecting changes that have occurred in the market since that time, but they are very similar. Q: And the essential goal of the conditions is the same, is it not? A: Yes." Ellison 20 Vol. 28.

76 "And it was only generator outlet, is what the need that was found in the order [in the 825 MW Wind Proceeding], correct? A: That is correct." Ellison 20 Vol. 40.

In addition, there are plenty of wind generation interconnection requests currently in the MISO queue to utilize the firm capacity provided by these lines:

> During September 2007 and October 2007, around the time of the Application filing, 25,032 MW of wind generation interconnection requests were filed at MISO. Most of the requester generation is located in the Minnesota, South Dakota, and North Dakota region. Further, many of the requested specific interconnection points are substations along the proposed Project lines.

(Ex. 257 at 16 (Ham Direct)).

And in the 825 MW Wind Outlet Proceeding, Xcel Energy, an investor-owned utility subject to the Commission's resource planning authority, was the only applicant and was solely responsible for developing the facilities that arose out of that case. (Ellison 20 Vol. 41). Here there are two Applicants, Xcel Energy and Great River Energy, as well as nine other participating utilities. These 11 utilities include investor-owned utilities, generation and transmission cooperatives and municipal power agencies. As Mr. Ellison admitted, the Commission's authority over these different types of utilities varies. (Ellison 20 Vol. 50-51). It is evident that MCEA did not consider the legal differences between the CapX2020 utilities in considering how their proposed conditions could ultimately be implemented.[77]

2. *Inappropriate Forum for Generation Decisions*

This is not the appropriate forum to make generation and fuel policy decisions. As transmission-owning utilities, Applicants are required to abide by the MISO Transmission and Energy Markets Tariff ("TEMT"). It requires open access and non-

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[77] "Q: So you're not suggesting that Great River Energy be required to bring its power purchase contracts to the Public Utilities Commission? A: No, I was suggesting that those utilities that are required to come to the Commission do so in a timely manner. Q: So is that a change you'd like to make in your testimony? Because I don't see where it says here it's limited to those utilities that are subject to PUC approval. A: It says utilities, and I think it implies utilities that have to come to the Commission. But if you want that more directly stated, yes, I'm only referring to utilities that are regulated by this Commission and would need Commission approval for contracts. Q: But you are mandating that Great River Energy enter into power purchase agreements, aren't you? A: As an applicant in this proceeding, yes." Ellison 20 Vol. 95-96.

discriminatory transmission service to all generators who seek access to the transmission grid. (Ex. 132 at 10 (Alders Rebuttal)).

This proceeding involves the development of transmission and transmission policy. The MCEA Conditions require judgments on generation and fuel policy that cannot properly be made in a transmission proceeding. No record has been developed on those judgments and the operative rules do not contemplate mixing generation/fuel policies with transmission policies. Rather, "[i]n this case, what [Applicants have] attempted to do is come up with long-range plan and these specific projects to provide transmission infrastructure to accommodate whatever generation decisions and policies might be set by the Commission." (Alders 13 Vol. 116).

3. *Conditions Lock up Needed Firm Capacity*

Under Minnesota law, public utilities are obligated to furnish "safe, adequate, efficient, and reasonable service" to their customers. Minn. Stat. § 216B.04. This includes an obligation to have sufficient generating capacity available to meet customer demands. (Ellison 20 Vol. 62). That generation must be supported by firm[78] transmission in order to qualify as capacity toward utilities' obligations.

The MCEA Conditions require that the "new firm transfer capability created by these lines [be] made fully available to renewable generation." (Ellison 20 Vol. 29). Thus, the MCEA Conditions preclude nonrenewable generation from using the lines' firm transfer capability. (Ellison 20 Vol. 29).

This seriously limits the capacity that utilities can count toward their obligations to serve. Variable resources, such as wind generation, currently provide only 12% to 15% of nameplate value for purposes of calculating planning and capacity requirements. (Ex. 132 at 22 (Alders Rebuttal)). Even Mr. Ellison admitted that

[78] "Firm" service is distinguished from "non-firm" service by its certainty. Firm service is contractually guaranteed; non-firm service is scheduled on an "as available" basis and is subject to interruption. *Compare* Order No. 888, F.E.R.C. Stats. & Regs. ¶ 31,036 at 31,931 (defining "firm" service), with *id.* at 31,932 (defining "non-firm" service).

redundant transmission would need to be built to support any nonrenewable capacity that is needed to satisfy the obligation to serve. (Ellison 20 Vol. 64-65).

MCEA attempts to downplay this problem by pointing out nonrenewable energy can flow on a non-firm basis in the real-time or Day 2 Market. (Ellison 20 Vol. 15. But this contention misses the point as under the applicable capacity rules, utilities need firm rather than non-firm transmission to provide capacity value to serve a utility's planning reserve requirement.

4. *Public Policy Considerations*

a. *Conditions Not Needed for RES Compliance*

Mr. Ellison stated that one of the "fundamental" purposes of the MCEA Conditions is to "ensure compliance with the Minnesota RES statute." (Ellison 20 Vol. 107). Yet, Minnesota utilities are already obligated by law to comply with the State's RES Statute and MCEA's proposed conditions do not alter that legal obligation.[79] Furthermore, there is no evidence that CapX Utilities subject to those requirements would fail to comply with those requirements.

The present proceeding is not the appropriate forum to ensure compliance with the RES Statute. An individual utility's compliance or noncompliance with the RES Statute is an issue that is addressed in each individual utility's resource plan or RES compliance report to the Commission. See Minn. Stat. § 216B.1691, subd. 3 ("Each electric utility shall report on its plans, activities, and progress with regard to the objectives and standards of this section in its filing under section 216B.2422 (Resource Planning Statute) or in a separate report submitted to the commission every

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[79] "Q: The first part of your answer, is it your opinion that without these conditions that utilities covered by the RES statute will simply ignore the statute? A: No, that's not my testimony. Q: Is it that the Commission will not enforce the statute without these conditions? A: No." Ellison 20 Vol. 107.

"Q: Then it isn't your testimony, is it, that in order for the RES to be satisfied, the Public Utilities Commission is legally obligated to adopt the conditions you propose? A: That is not my testimony, correct." Ellison 21 Vol. 17-18.

two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section.").

The record establishes RES compliance is not an issue given Ms. Peirce's unrebutted testimony that the CapX2020 utilities are all in compliance. (Peirce 22 Vol. 108-109). Mr. Alders also testified, that Xcel Energy is committed to acquiring, through purchase or construction, sufficient renewable generation to meet the RES goals irrespective of the particular use of these lines. (Alders 15 Vol. 18).

b. *Conditions Accelerate Statutory Milestones*

The RES Statute sets forth a long-term requirement with milestones to ensure a phase in of the requirement. The milestones include requiring 12% renewable penetration by 2012 and 17% by 2016. Minn. Stat. § 216B.1691, subd. 2a(a). The MCEA Conditions require generation commitments to be made two years in advance of the in-service date of the lines. This means that generation commitments would need to begin being made by as early as 2009 to accommodate the 2011 in-service date for the Monticello – St. Cloud segment of the Fargo Project. (Ex. 132 at 24 (Alders Rebuttal)). Similarly, major generation commitments would need to be made by 2010 to accommodate the current schedule of completing the western portion of the Brookings Project by 2012. (Ex. 132 at 23-24 (Alders Rebuttal)).

As a result, the MCEA Conditions would require 1,000 MW of extra wind generation capacity within the next two years. (Ex. 132 at 24 (Alders Rebuttal)). This amount of capacity would result in the overall RES goals being accelerated by several years. (Ex. 132 at 24 (Alders Rebuttal)). While the RES Statute does not preclude early compliance, the Legislature was careful to phase in RES compliance and the MCEA conditions would override this approach. For example, Xcel Energy intends to deploy approximately 500 MW of small, community-based wind projects by 2010. (Ex. 132 at 25 (Alders Rebuttal)). In addition, Xcel Energy has committed to develop approximately 200 MW per year of other wind projects over the next decade or more. (Ex. 132 at 25 (Alders Rebuttal)). The MCEA Conditions would likely require modification of both of these strategies. (Ex. 132 at 25 (Alders Rebuttal)). Other utilities would also likely modify their strategies to accommodate these conditions.

c. _Conditions Discourage Proactive Planning_

Proactive and long-range transmission planning is the most appropriate effective planning approach that should be encouraged by the Commission. It allows utilities to stay out ahead of customer requirements, overall system needs, as well as the RES requirements. (Ex. 132 at 27 (Alders Rebuttal)). Imposing the MCEA Conditions may discourage such proactive transmission planning. By locking up the transmission capacity for a single purpose, in the future, utilities will be forced to analyze whether that particular purpose, in isolation, justifies a transmission project. (Ex. 132 at 27 (Alders Rebuttal)). Concerned about the statutory RES milestones, utilities may consider whether to defer transmission projects into future time frames that better match the statutory milestones. (Ex. 132 at 28 (Alders Rebuttal)).

The MCEA Conditions could encourage smaller, incremental transmission projects to avoid over-committing. (Ex. 132 at 28 (Alders Rebuttal)). This would discourage proposing major facilities that exceed the bare minimum necessary to ensure system operation. (Ex. 132 at 28 (Alders Rebuttal)). In sum, "future applicants would have no incentive to propose new transmission which would create incremental transfer capability greater than their own immediate needs, resulting in a balkanized, less efficient transmission system." (Ex. 308 at 4 (Rakow Statement)).

d. _Conditions Disadvantage C-BED Projects_

Smaller generators would also be at a disadvantage if the MCEA Conditions are imposed. By "ordering the conditions the Commission will be seen as establishing policy that discourages small wind development in favor of large wind facilities." (Ex.

308 at 5 (Rakow Statement); Ex. 132 at 28 (Alders Rebuttal)). This problem is not solved by reforms in the MISO queuing process, as it is undisputed that queue reform does not materially improve processing time in constrained areas like the Buffalo Ridge that could allow for advantageously priced C-BED proposals. (Ex. 135 at 18-19 (MISO White Paper)). As a result, even with the recent reform, in constrained areas, the MCEA Conditions will operate in the same manner as under the current system.

e. *Conditions Distort Market Forces*

The MCEA Conditions also restrict normal market and competitive forces that work to ensure that the most cost-effective generation is purchased by utilities. Market limiters restrict the competitiveness of the market by limiting the number of potential projects.[80] A forced implementation schedule will distort price signals and result in utilities selecting more expensive project just because they have higher queue positions. (Ex. 132 at 33 (Alders Rebuttal)).[81] Also, the MCEA Conditions could effectively freeze out the larger market for wind energy by impeding wind energy transactions outside Minnesota. (Ex. 132 at 33 (Alders Rebuttal)). In the end, consumers would pay these increased costs. (Ex. 308 at 4 (Rakow Statement)).

f. *Conditions Prejudge Generation Policy*

Decisions about generation and fuel-type should be made in resource-planning proceedings and not in a specific power line permitting proceeding. It is not possible for this record to address all of the considerations that should be considered in making a resource selection decision. (Ex. 132 at 29 (Alders Rebuttal)).

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[80] As Mr. Alders explained "an obligation to meet a certain amount of wind power in a certain location by a certain date has the effect of reducing . . . competition. It reduces the geography, it reduces timing, it reduces the number of competitors within the market . . . ." Alders 15 Vol. 105.

[81] As Mr. Webb noted "if you have transmission that extends in different multiple directions, it allows the flexibility to take advantage of the most cost-effective generation that may be available, whatever that may be." Webb Vol. 4 Vol. 156.

5. *Conditions Not Necessary*

Finally, the MCEA Conditions are not necessary to achieve the result of developing substantial amounts of wind generation in and around Minnesota. The record shows that significant interest in wind generation is available and will be developed without imposing these conditions. Mr. Webb points out 58 projects representing 4,358 MW of wind-energy generation have been studied specifically in connection with the Brookings Project. (Ex. 56 at 35 (Webb Direct)). This far exceeds the 700 MW from the Brookings Project. (Ex. 104 at 5 (Alholinna Direct)). Given the number of projects in the MISO queue, it is highly likely that cost-effective wind-energy projects will be able to take advantage of the capacity created by the proposed transmission lines. (Ex. 132 at 21 (Alders Rebuttal)). In addition, interest in developing wind-energy projects is strong and increasing due to the State's RES and renewable energy initiatives throughout the region.

IX. CONCLUSION

Applicants respectfully request that the ALJ conclude they have satisfied the Commission's requirements to establish three separate need categories – community service reliability, system-wide growth, and generation outlet – that must be addressed soon to maintain reliable service to utility customers throughout the State. Applicants further request that the ALJ conclude that the 345 kV Projects will best address these needs and recommend that the Commission grant Certificates of Need, without material substantive conditions, to Applicants. Finally, Applicants request that the ALJ adopt the Proposed Findings submitted along with this Brief.

Dated: October 24, 2008

Respectfully submitted:

BRIGGS AND MORGAN

By: ______________________

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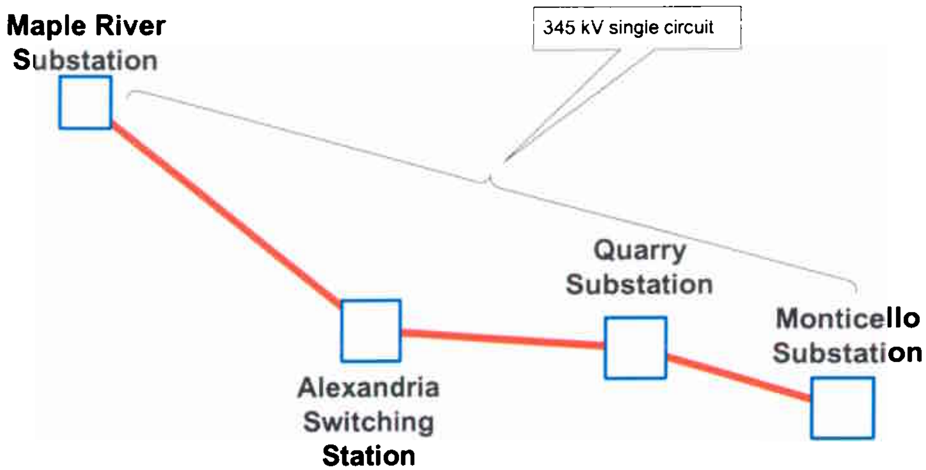
CapX2020: Twin Cities – Fargo 345 kV Project

Docket No. E-002/CN-06-1115
OAH Docket No. 15-2500-19350-2
Applicants' Post-Hearing Brief
ATTACHMENT A

Application Proposal



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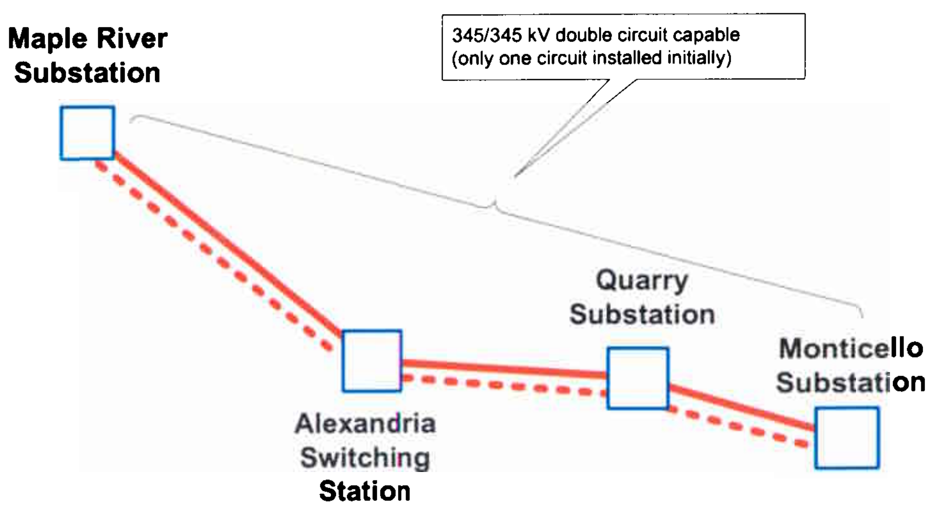


Legend

As to type of construction

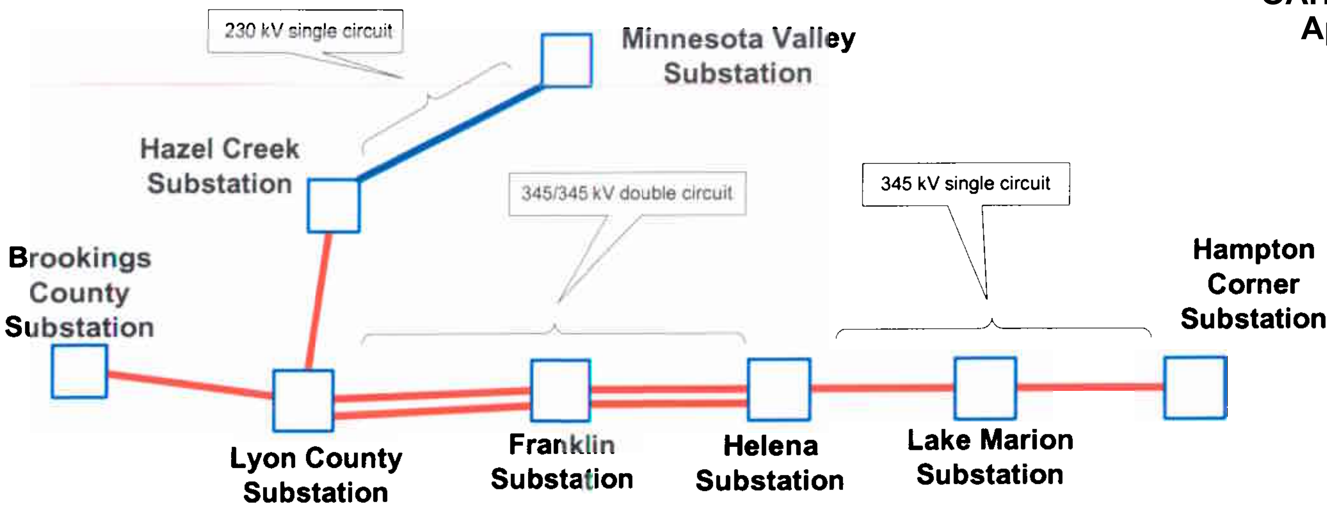
- 345 kV circuit
- Potential 2nd 345 kV circuit (installed in the future on the same poles as initial 345 kV circuit)

EXHIBIT 22
tabbies

CapX2020: Twin Cities – Brookings County 345 kV Project

Docket No. E-002/CN-06-1115
OAH Docket No. 15-2500-19359-2
Applicants' Post-Hearing Brief
ATTACHMENT B

Application Proposal



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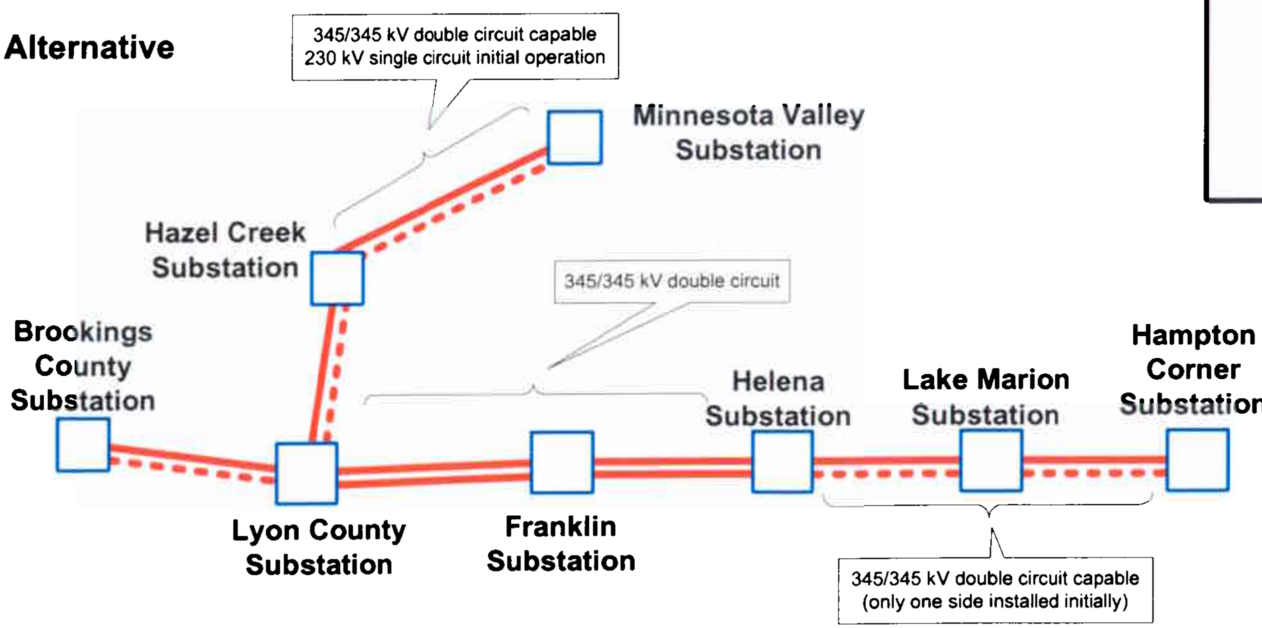


Legend

As to type of construction

345 kV circuit

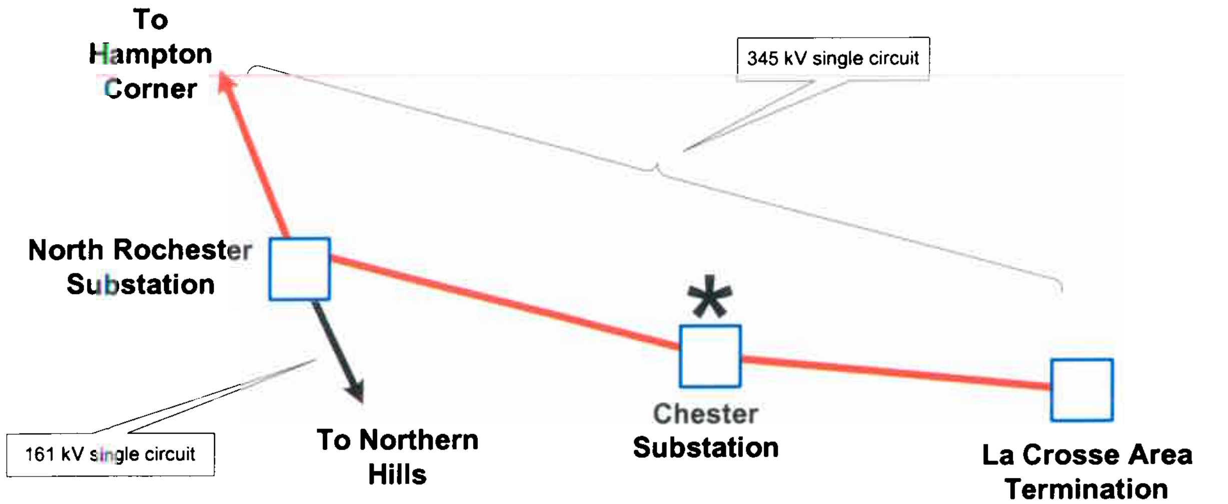
Potential 2nd 345 kV circuit (installed in the future on the same poles as initial 345 kV circuit)

EXHIBIT
23

CapX2020: Twin Cities – La Crosse 345 kV Project – *Southern Crossing*

Docket No. E-002/CN-06-1115
OAH Docket No. 15-2500-19350-2
Applicants' Post-Hearing Brief
ATTACHMENT C

Application Configuration (as amended in Stevenson direct testimony)



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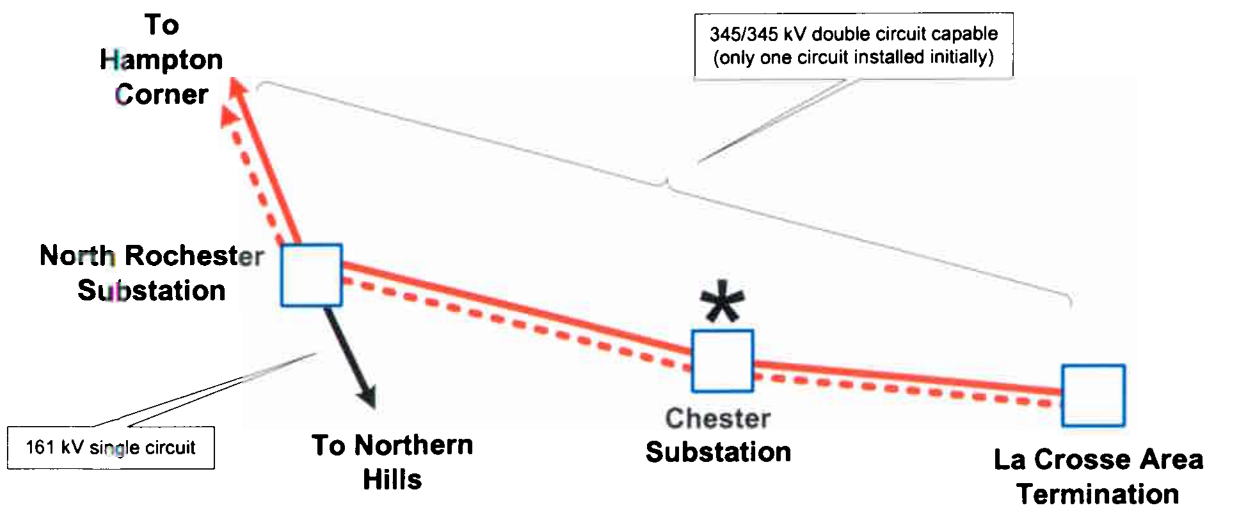

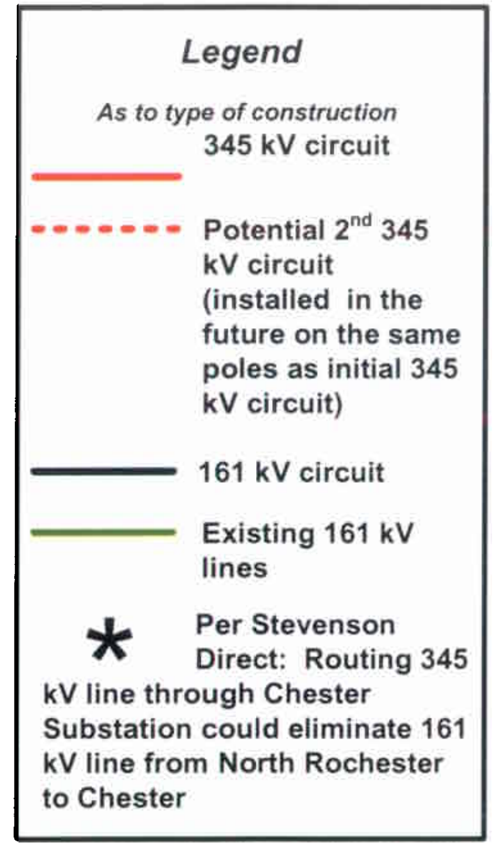

EXHIBIT
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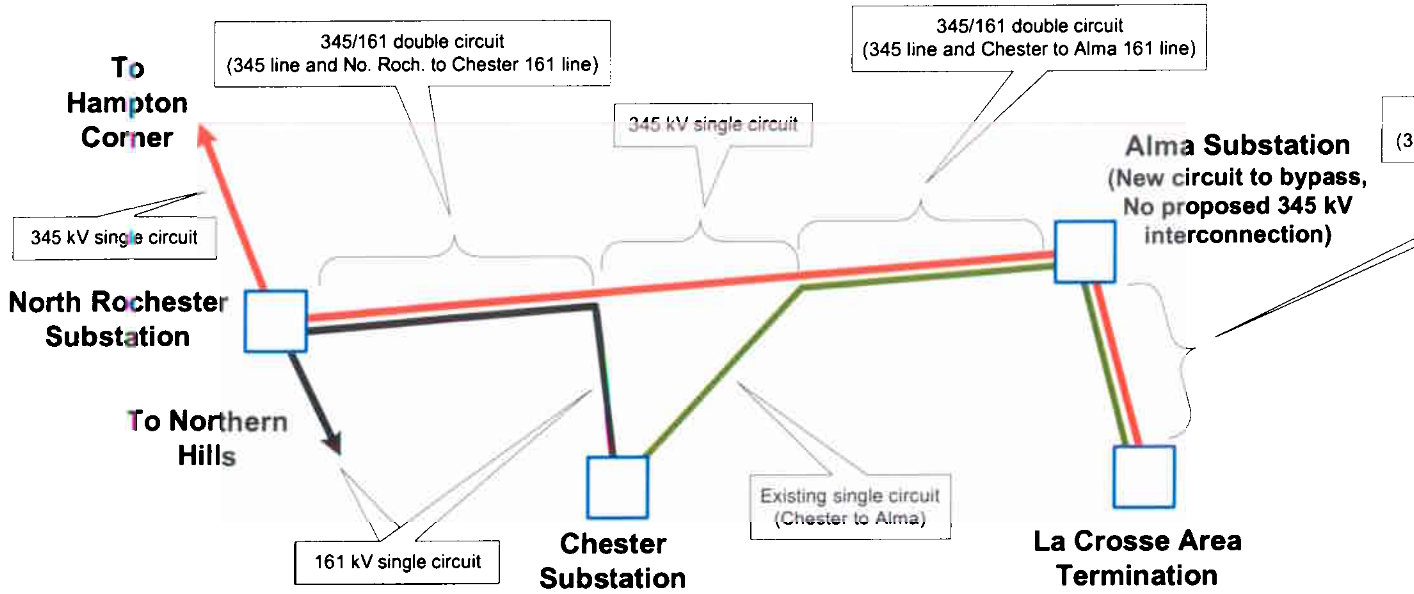
CapX2020: Twin Cities to La Crosse 345 kV Project – *Alma Crossing*

Docket No. E-002/CN-06-1115
OAH Docket No. 15-2500-19350-2
Applicants' Post-Hearing Brief
ATTACHMENT D

Application Configuration



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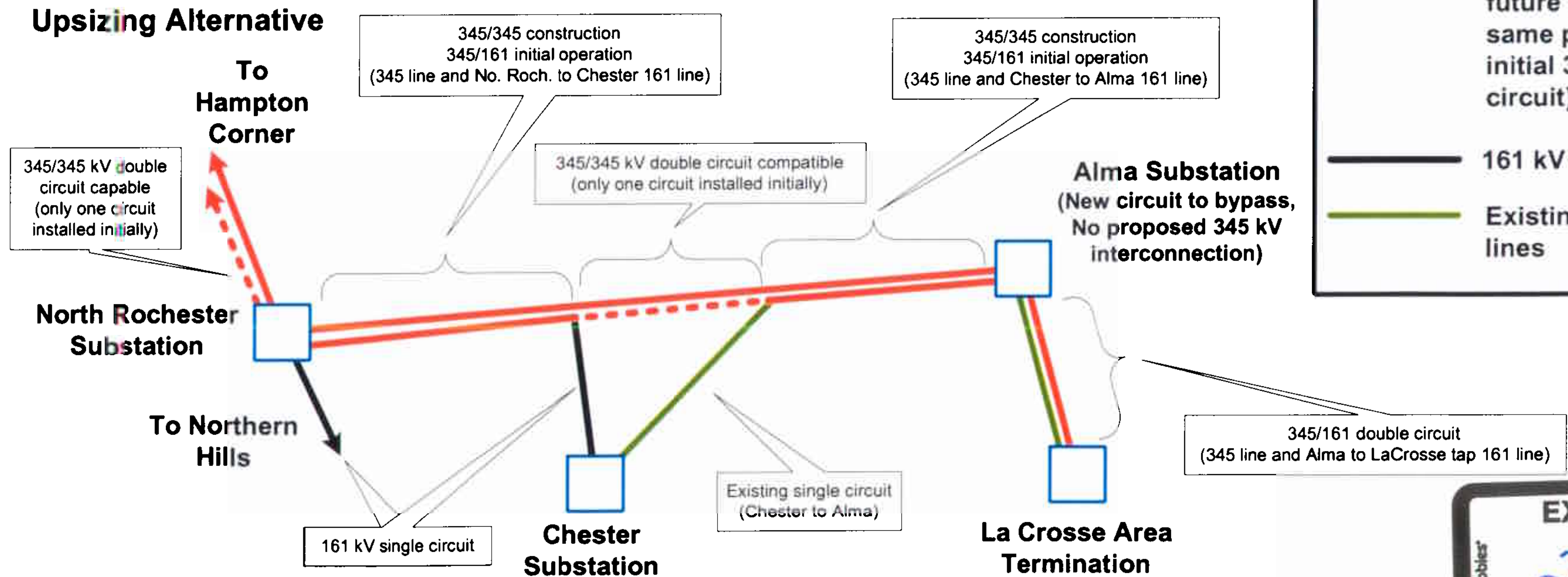

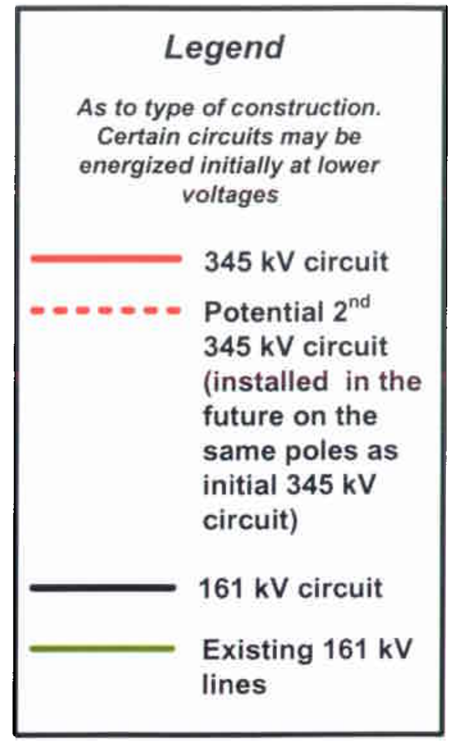

Figure 2-14. More detailed engineering analysis and design could be done to verify preliminary results and to design cost effective solutions.

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OAH Docket No. 15-2500-19350-2
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ATTACHMENT E

Figure 2-14: Underlying Facilities

Overloaded facility	Line or sub	Voltage	Units (either mileage or count of equipment)
Stoughton Muni – Stoughton 69 kV 1	L	69	1
Sun Prairie South – Colorado 69 kV 1	L	69	4
Creston – Summit Lake North 69 kV	L	69	4
Ottumwa – South Ottumwa 69 kV	L	69	4
Summit Lake North – Summit Lake South 69 kV	L	69	1
Hayward-South Shore 69 kV 1	L	69	4
Thompson Lake – Remmele 69 kV	L	69	6
Crystal Tap – Arlington 69 kV	L	69	7
Crystal Tap – Gaylord 69 kV	L	69	1
Fort Ridgely – Schilling Tap 69 kV	L	69	1
Gaylord – Heartland 69 kV	L	69	6
Winthrop – Cornish 69 kV	L	69	3
Winthrop – Heartland 69 kV	L	69	1
Sauk River – Quarry 115 kV	L	115	1
Sauk River – West Saint Cloud 115 kV	L	115	1
Burnsville – Dakota Heights 115 kV	L	115	7
Dakota Heights – Kenrick 115 kV	L	115	5
Lake Marion – Kenrick 115 kV	L	115	4
Sheyenne – Fargo 230 kV	L	230	4
Blue Lake – Helena Switching Station 345 kV	L	345	25
Council Creek 138/69 kV transformer 1	S		1
Petenwell 138/69 kV transformer 1	S		1
Elk 161/69 kV transformer 2	S		1
Lansing 161/69 kV transformer	S		1
Hazleton 161/69 kV transformer	S		1
Hayward 161/69 kV transformer	S		1
Post 161/69 kV transformer	S		1
Lake Marion 115/69 kV transformer 2	S		1
Maple River 345/230 kV transformers 1 and 2	S		1
Franklin 115/69 kV transformer 1	S		1
Franklin 115/69 kV transformer 2	S		1
Monroe Co. 161/69 kV transformer	S		1
Morris 230/115 kV transformer	S		1

Utility	Total Annual Revenue Requirement	2015 System MWh	Capital Cost / kWh	Line Loss Benefit / kWh	Net Cost / kWh	800 kWh / Month
CMMPA	$ 1,026,556	534,280	$ 0.0019	$ 0.0003	$ 0.0016	$ 1.28
DPC	$ 10,363,048	6,257,662	$ 0.0017	$ 0.0003	$ 0.0013	$ 1.07
GRE	$ 25,841,040	16,656,661	$ 0.0016	$ 0.0003	$ 0.0012	$ 0.98
MP	$ 11,449,100	13,095,163	$ 0.0009	$ 0.0003	$ 0.0006	$ 0.44
MRES	$ 3,953,750	4,771,347	$ 0.0008	$ 0.0003	$ 0.0005	$ 0.40
OTP	$ 13,950,300	5,179,410	$ 0.0027	$ 0.0003	$ 0.0024	$ 1.90
RPU	$ 6,220,000					
SMMPA	$ 6,521,130	3,712,999	$ 0.0018	$ 0.0003	$ 0.0014	$ 1.15
WPPI	$ 1,728,072	6,376,623	$ 0.0003	$ 0.0003	$ (0.0001)	$ (0.04)
XCEL	$ 145,862,895	48,425,628	$ 0.0030	$ 0.0003	$ 0.0027	$ 2.15
	$ 226,915,891	105,009,773	$ 0.0022	$ 0.0003	$ 0.0018	$ 1.47
SOURCE	Appendix D-5	Appendix C-7 & Supplement of 11.27.07				

Annual Line Loss Benefit † $33,984,057
Annual MWh 105,009,773
Annual Benefit / kWh $ 0.0003

† = 234.2 MW * 8,760 hrs * .415 capacity factor * $53.22 LMP * 0.75 allocator to others

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ATTACHMENT F

EXHIBIT
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