BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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IN THE MATTER OF THE APPLICATION FOR CERTIFICATES OF NEED FOR THREE 345 kV TRANSMISSION LINE PROJECTS WITH ASSOCIATED SYSTEM CONNECTIONS	Docket No. ET2,E002, et al./CN-06-1115

DIRECT TESTIMONY OF DR. STEVE RAKOW

ON BEHALF

OF THE MINNESOTA OFFICE OF ENERGY SECURITY

MAY 23, 2008

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I. INTRODUCTION

Q. What is your name, business address, and occupation?

A. My name is Dr. Steve Rakow. My business address is 85 Seventh Place East, Suite 500, St. Paul, Minnesota 55101-2198. I am employed as a Public Utilities Rates Analyst with the Minnesota Office of Energy Security (OES).

Q. What is your educational and professional background?

A. A summary of these items is included as OES Exhibit No. ___ (SRR-1). In addition, I note that all information requests and responses referred to in this text are available in OES Exhibit No. ___ (SRR-2).

Q. What are your responsibilities in this proceeding?

A. I am submitting testimony on behalf of the OES that:

- summarizes the *Application for Certificates of Need for Three 345 kV Transmission Line Projects with Associated System Connections* (Petition);
- presents the criteria established by Minnesota Statutes and Minnesota Rules that the Minnesota Public Utilities Commission (Commission) will use to decide whether to approve the Petition;
- introduces the other witnesses sponsored by the OES in this proceeding;
- provides the OES's analysis of alternatives and policy; and
- summarizes the OES's overall conclusions and recommendations at this time.

II. SUMMARY OF CERTIFICATE OF NEED

A. THE APPLICANTS' CASE

1. Summary of the Applicants

Q. Who are the applicants for certificates of need in this proceeding?

A. Northern States Power Company, a Minnesota Corporation and wholly-owned subsidiary of Xcel Energy Inc. (Xcel) and Great River Energy, a Minnesota Cooperative Corporation (GRE) request certificates of need for several transmission facilities. Thus, Xcel and GRE (jointly, the Applicants) are the applicants for the certificates of need (CN). As indicated in the Petition at page 1.29, it is estimated at this time that several additional utilities[1] will own portions of the proposed transmission lines. These additional utilities are not applicants, but their estimated baseline ownership shares are provided in Figure 1-11 of the Petition.

Q. In the past has there been a similar distinction between applicants for a CN and utilities participating in a project?

A. A similar situation regarding applicants (but at a much smaller scale) arose in the *Petition of Northern States Power Company d/b/a Xcel Energy and Dairyland Power Cooperative for a Certificate of Need for a 115 kV and 161 kV Transmission Line from Taylors Falls to Chisago County Substation* (Chisago Petition); see Docket No. E002, ET3/CN-04-1176. In the Chisago Petition, it was noted that at least one other entity may seek to pay for a portion of the facility and thus the question was raised regarding what constituted an

[1] Specifically, Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, and Wisconsin Public Power.

applicant. The October 2, 2007 *Initial Post-hearing Brief of the Minnesota Department of Commerce* stated at pages 7-8:

> Regarding the determination of which entity is an applicant, Minnesota Statutes §216B.243 subdivision 2 refers to the facility itself and provides that "no large energy facility" can be constructed without a CN. Regarding the definition of an applicant, Minnesota Statutes §216B.243 subdivision 4 states only that "any person proposing to construct a large energy facility shall apply for a certificate of need." Clearly, the statute allows for latitude in determination of applicants; it does not define an applicant but requires the applicant to make the necessary showings.

On February 20, 2008, the Commission granted a certificate of need to these applicants.

Further, as discussed below, Minnesota Rules pertaining to certificates of need have a specific provision allowing for changes in ownership. Therefore, I conclude that it is reasonable for GRE and Xcel to serve as applicants in this docket even though they are not likely to be the sole owners of the proposed facilities. Any such changes in ownership can be addressed through Commission rules.

As mentioned above, the Applicants have provided an estimated baseline ownership structure in Figure 1-11 on page 1.29 of the Petition. However, the Petition also notes that the final ownership structure may differ. Changes in ownership can affect the analysis of alternatives by changing the cost of capital. However, the ownership of the proposed facilities does not affect the need analysis because the Applicants do not claim need based upon their own systems. Rather, they claim need based upon larger—statewide and regional—factors. Further, the Petition is clear that there may well be changes in ownership shares and explains the mechanism for doing so. Therefore, I will analyze the alternatives using a range of cost of capital values to reflect a variety of final ownership outcomes.

Q. What happens if the actual ownership differs from that indicated in the Petition?

A. The CN rules cover changes in the ownership of proposed facilities approved by the Commission. Specifically, Minnesota Rules 7849.0400 subpart 2 H states:

> If an applicant determines that a change in size, type, timing, or ownership other than specified in this subpart is necessary for a large generation or transmission facility previously certified by the commission, the applicant must inform the Commission of the desired change and detail the reasons for the change.

Based upon the Applicants' Petition and Minnesota Rules 7849.0400 subpart 2 H, it appears that, once final ownership is determined, if that ownership is different from that outlined in Figure 1-11 then the Applicants may be required to make a compliance filing under Minnesota Rules 7849.0400 subpart 2 H. It would be useful if the Commission's Order in this docket were to clarify this point.

Regarding the potential future compliance filing, according to the rules, "the Commission shall order further hearings if and only if it determines that the change, if known at the time of the need decision on the facility, could reasonably have resulted in a different decision under the criteria specified in part 7849.0120." Since the proposed need is regional and I will have already analyzed the alternatives under a variety of ownership outcomes, there should be no need for further hearings. However, the potential future compliance filing will serve as a simple way for the Applicants to inform the Commission of the final ownership structure for the proposed facilities, should the Petition be approved by the Commission. It will also serve as a forum for other parties to provide feedback to the Commission regarding the need for additional hearings on ownership issues.

2. Summary of the Petition

Q. Please summarize the Petition.

A. As described in the Petition, the Applicants request CNs for the following projects and associated system connections:

- Twin Cities—La Crosse, WI: A 150-mile, 345 kV transmission line between the southeast corner of the Twin Cities, Rochester, and La Crosse, Wisconsin. This project also includes two new 161 kV transmission lines from the North Rochester substation into the Rochester area.
- Fargo, ND—Twin Cities: A 250-mile, 345 kV transmission line between Monticello, St. Cloud, Alexandria, and Fargo, North Dakota.
- Brookings, SD—Twin Cities: A 200-mile, 345 kV transmission line between the southeast corner of the Twin Cities and Brookings, South Dakota as well as a 25-mile, 345 kV transmission line from Marshall to a new substation called Hazel Creek in the Granite Falls area and a 10-mile, 230 kV transmission line from the new Hazel Creek substation to the Minnesota Valley substation in Granite Falls.

Q. Are CNs required for the proposed facilities?

A. Yes, for the following reasons. First, Minnesota Statutes §216B.2421, subd. 2 (2) defines a large energy facility (LEF) as "any high-voltage transmission line with a capacity of

200 kilovolts or more and greater than 1,500 feet in length." Since the following proposed facilities generally have a design capacity of above 200 kV and are greater than 1,500 feet in length they qualify as LEFs:

- approximately 150-mile, 345 kV transmission line between a new Hampton Corner substation in the southeast corner of the Twin Cities, Rochester, and La Crosse, Wisconsin (Twin Cities—La Crosse, WI line);
- approximately 250-mile, 345 kV transmission line between Monticello and Fargo, North Dakota (Fargo, ND—Twin Cities line);
- approximately 200-mile, 345 kV transmission line between Brookings, South Dakota and a new Hampton Corner substation in the southeast corner of the Twin Cities (Brookings, SD—Twin Cities line);
- approximately 25-mile, 345 kV transmission line from Marshall to a new Hazel Creek substation in the Granite Falls area; and
- approximately 10-mile, 230 kV transmission line from Hazel Creek to the Minnesota Valley substation in Granite Falls.

Second, Minnesota Statutes §216B.2421, subd. 2 (3) defines an LEF as "any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota or that crosses a state line." As noted above, some of the proposed transmission lines cross state borders. Further, since the following proposed facilities have a design capacity above 100 kV and are greater than 10 miles in length they qualify as LEFs:

- 10 to 15 mile, 161 kV transmission line from the North Rochester substation to the Northern Hills substation; and

- 20 to 30 mile, 161 kV transmission line from the North Rochester substation to the Chester substation.

Third, Minnesota Statutes §216B.243, subd. 2 states that "no large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need by the Commission…" Therefore, CNs are required to be approved by the Commission before the proposed high voltage transmission lines (HVTLs) could be sited or constructed.

Q. Did you investigate the list of underlying facilities for projects that might require a CN?

A. Yes. The Petition provides a list of underlying facilities[2] provided in Figure 2-14 on page 2.18 of the Petition. The Petition states that the listed facilities could be "overloaded in some circumstances." OES Information Request No. 3 requested the Applicants identify the facilities where the anticipated best solution would qualify as an LEF under Minnesota Statutes §216B.2421. The Applicants' response was that "none of the anticipated solutions for the overloaded facilities in the underlying electrical system includes any new transmission lines that meet the definitions set forth in [Minnesota Statutes §216B.2421 subdivision 2 parts (2) and (3)]." In other words, none of the anticipated solutions for overloaded facilities would be an LEF.

Furthermore, OES Information Request No. 22 and Minnesota Center for Environmental Advocacy, Wind on the Wires, Izaak Walton League of America—Midwest Office, and Fresh Energy (collectively, Joint Intervenors) Information Request

[2] Underlying facilities are portions of the transmission network (69 kV lines, transformers, etc.) that must be modified before the proposed facilities can operate as proposed.

No. 2 requested additional information regarding the underlying facilities for the Brookings, SD—Twin Cities line. The Applicants' response to Joint Intervenor Information Request No. 2 provided an updated list of underlying facilities and indicated that the Hazel Creek—Minnesota Valley 230 kV line may need to be constructed as either single circuit or double circuit 345 kV. Specifically, the response states "To maximize performance of the system, the voltage of the connection between Minnesota Valley Substation and Hazel Creek Substation should be the same as the voltage of the connection between Minnesota Valley Substation and Blue Lake Substation." Therefore, I recommend that, in rebuttal testimony the Applicants provide an update regarding the certification request for the voltage and number of circuits of the Hazel Creek—Minnesota Valley segment.

Q. When must the Commission make a decision regarding the Petition?

A. Minnesota Statutes §216B.243, subd. 5 states "Within 12 months of the submission of an application, the Commission shall approve or deny a certificate of need for the facility." While the Commission can extend this time given consent of the parties or for good cause shown, barring those two factors means that under the CN process the due date for a Commission decision regarding the Petition is 12 months from the date of the Applicants' submission of additional data. The Commission's November 21, 2007 *Order Accepting Application as Substantially Complete Pending Supplemental Filing* (Completeness Order) states at point 2 that "The Application for Certificates of Need for Three 345 kV Transmission Line Projects with Associated System Connections will become substantially complete upon the filing of the following information …"

On November 21, 2007, the Applicants filed their *Supplement to their Application to the Minnesota Public Utilities Commission for Certificates of Need for Three 345 kV Transmission Line Projects with Associated System Connections* (Supplement). Thus the due date for a Commission decision is November 21, 2008.

Q. How do the Applicants justify the need for the proposed HVTLs?

A. On page 1.4 of the Petition the Applicants summarize their claim that the proposed HVTLs are needed for three reasons:

- community service reliability: the lines are needed to meet reliability concerns in:
  - La Crosse, WI;
  - Rochester, MN;
  - St. Cloud, MN;
  - Alexandria, MN; and
  - the southern Red River Valley, (ND and MN);
- system-wide growth: the lines are needed to meet 4,500 to 6,300 MW of additional demand by 2020;[3] and
- generation outlet: the lines are needed to support development of new generation.

Note that all three claimed needs revolve around capacity rather than energy. The first issue, community service reliability is claimed to be an issue because MW demand exceeds the MW supply capacity of the system in certain local areas. The second issue,

[3] This range is taken from the underlying CapX transmission study—See Appendix A-1 of the Petition.

system-wide growth, is claimed to be an issue because of the forecasted growth in MW demand. The third issue, generation outlet, is claimed to be an issue in that more MW of generation are forecasted to request interconnection than the existing system can be expected to handle.

B. THE OES'S CASE

Q. Please introduce the witnesses sponsored by the OES in this proceeding.

A. In addition to myself, the OES is sponsoring five other witnesses in this proceeding:

- Mr. Christopher J. Shaw;
- Mr. Christopher T. Davis;
- Mr. Hwikwon Ham; and
- Ms. Susan Peirce.

I address issues related to alternatives and policy. The testimony of the remaining witnesses is illustrated in OES Exhibit No. ___ (SRR-3). Referring to that exhibit, Mr. Ham addresses issues regarding forecasting—steps one (demand forecast and energy forecast), five (load & capability report), six (total interconnect need), and seven (load growth). Mr. Davis addresses issues regarding demand-side management (DSM)—steps two (DSM study – 1% - 1.5% MWh) and three (MW equivalent of step 2). Ms. Pierce addresses issues regarding renewable energy objective compliance—step four. Mr. Shaw addresses issues regarding load and capability—step five in conjunction with Mr. Ham.

Q. Please summarize the criteria to be considered by the Commission during this proceeding and explain generally how the OES addresses the criteria.

A. There are several factors to be considered by the Commission in making a determination in CN proceedings. In a general manner, these factors are located in different sections of Minnesota Statutes. Some of the statutory criteria are reflected in a more specific way in Minnesota Rules part 7849.0120. However, some statutory criteria are not reflected in rules (for example, the ‘innovative energy project’ language of §216B.1694, subd. 2). To clarify this situation, a comprehensive list of the criteria and how they are addressed by the OES’s witnesses is provided in OES Exhibit No. ___ (SRR-4). Note that in OES Exhibit No. ___ (SRR-4) several of the rule criteria have been moved from their location in the rule; this was done to better focus the testimony of the OES’s witnesses on their areas of expertise and enable the OES to present a more coherent overall analysis and recommendation.

III. ANALYSIS OF RENEWABLE PREFERENCE

Q. What criterion do you consider in terms of renewable preference?

A. Regarding renewable preference, there are two sections of Minnesota Statutes that refer to CNs.

First, Minnesota Statutes §216B.243, subd. 3a states that:

> The Commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and

> geothermal energy and the use of trees or other vegetation as fuel.

Second, Minnesota Statutes §216B.2422, subd. 4 states that:

> 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 nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest."

Q. Please provide your analysis of renewable preference.

A. I note that the transmission lines in question are not proposed to interconnect with any particular generation resource. Rather, as discussed above, the lines are proposed to serve three functions:

- community service reliability;
- system-wide growth; and
- generation outlet.[4]

Because the transmission lines in question are not proposed for and will not interconnect any particular generation resource, I conclude as a practical matter that the renewable preference statutes, including Minnesota Statutes §§ 216B.243, subd. 3a and 216B.2422, subd. 4, do not establish additional standards that the Applicants must satisfy as part of this CN proceeding.

Q. Is there other information related to renewable energy and the proposed transmission lines?

[4] See page 1.4 of the Petition.

A. The *Renewable Energy Standards Report 2007*, filed November 1, 2007 in Docket No. E999/M-07-1028 (RES Report) states that "The law requiring the utilities to file this Renewable Energy Standards Report requires the utilities to report on specific transmission line proposals that are necessary to meet intermediate RES milestones." The RES Report is the proper forum for analyzing how the utilities will plan and build the transmission necessary to meet the RES. The RES Report lists the following lines as necessary for this purpose; in addition, I provide a quote from the RES Report regarding the reason the line is necessary:

- Fargo, ND to Twin Cities 345 kV Project—"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."
- Brookings, SD to Twin Cities 345 kV Project—"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."

Therefore, both the Fargo, ND—Twin Cities line and the Brookings, SD—Twin Cities line are part of the overall plan to meet intermediate RES milestones.

Q. Please summarize your analysis under the renewable preference statutes.

A. I conclude that the renewable preference statutes do not apply.

IV. ANALYSIS OF ALTERNATIVES

A. SIZE, TYPE, AND TIMING ANALYSIS

Q. What criterion do you consider in terms of size, type, and timing of the Applicants' proposed Project?

A. Minnesota Rules 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."

Q. Please provide the definitions of size, type, and timing that you use.

A. In this case, I use the following definitions:

- size—refers to the quantity of power transfers that the transmission infrastructure improvement enables;
- type—refers to the transformer nominal voltages, rated capacity, and nature (AC or DC) of power transported; and
- timing—refers to the on-line date for the transmission infrastructure improvements.[5]

1. Size Analysis

Q. Please explain how your definition of size relates to the Applicants' claimed needs.

A. In this case, the Applicants' claimed need is three-fold:

[5] The discussion of size, type, and timing is based upon the *Direct Testimony and Exhibit of Samir Ouanes*, filed April 11, 2002 in Docket No. E002/CN-01-1958 (Ouanes Direct). The definition of type is taken from Northern States Power Company d/b/a Xcel Energy's response to Department Information Request No. 62, included in the Ouanes Direct as DOC Exhibit No. ___ (SO-12).

- community service reliability—meeting demand in local areas such as Rochester, La Crosse, Wisconsin, St. Cloud, Alexandria, and the Red River Valley;
- system-wide growth—4,500 to 6,300 MW of new demand in the region; and
- generation outlet/renewable energy support—allow new renewable and non-renewable generation in southwestern Minnesota and elsewhere.

Regarding community service reliability, size refers to the ability to provide supply sufficient to meet local demand for a reasonable duration. Regarding system-wide growth, size refers to the ability to connect the 4,500 to 6,300 MW of new demand with supply resources. Regarding generation outlet/renewable energy support size refers to the ability to connect sufficient renewable generation to meet Minnesota Statutes §216B.1691 (renewable energy objectives). Note that for system-wide growth to be met, most likely generation outlet will have to be created for renewable and non-renewable resources.

Q. Please provide your analysis of the appropriateness of the Applicants' proposed size in terms of community service reliability for the Twin Cities—La Crosse, WI line.

A. For the La Crosse, Wisconsin region, chapter 9 of Appendix A-2 of the Petition (the *La Crosse 161 kV Load Serving Study*) concludes that a 161 kV alternative only allows sufficient supply to meet demand through 2014. This engineering conclusion demonstrates that lower (100 kV class) voltages are insufficient to address the need in the La Crosse, Wisconsin region for a reasonable duration because their size is too small.

For the Rochester region, chapter 8 of Appendix A-2 of the Petition concludes that both a 161 kV line (addresses need through 2033) and a 345 kV line (addresses need though 2051) were viable in that they would enable sufficient power transfers. However, a 345 kV line is necessary to enable sufficient power transfers to serve La Crosse, WI for a reasonable duration. Thus, a 345 kV project allows a single project to solve multiple community service reliability issues. Based upon this information, I conclude that the Applicants' proposed size for the Twin Cities—La Crosse, WI line is reasonable.

Q. Please provide your analysis of the appropriateness of the Applicants' proposed size in terms of community service reliability for the Fargo, ND—Twin Cities line.

A. Table 5.1A on pages 24-25 of Appendix A-3 of the Petition indicates that the Fargo, ND—Twin Cities line adequately addresses the load serving needs in the south zone (including both St. Cloud and Alexandria sub-areas), meaning that the line "provides a long-term solution to the deficiency." However, the Fargo, ND—Twin Cities line only partially addresses the load serving needs in the north zone, meaning that "additional transmission facilities would be required for that source to be fully effective, or that it is a short-lived solution, providing for less than 25 percent load growth from 'existing' (2003/2004) levels." Further, the Fargo, ND—Twin Cities line "is not effective at addressing the load-serving deficiency" for the Bemidji sub-area. There is further discussion of the Fargo, ND—Twin Cities line in terms of community service reliability on pages 4.16 to 4.35 of the Petition.

Based upon the results for the south zone presented in Table 5.1A of Appendix A-3 and Figures 4-13, 4-16, and 4-19 of Chapter 4 of the Petition I conclude that the

Applicants' proposed size for the Fargo, ND—Twin Cities line appears to be reasonable in terms of community service reliability because it would enable sufficient power transfers to resolve the south zone issues. However, it appears that additional facilities may be needed for both the north zone and the Bemidji sub-area; the need for these facilities will be evaluated in Docket No. E017,E015,ET6/CN-07-1222.

Q. Please provide your analysis of the appropriateness of the Applicants' proposed size in terms of community service reliability for the Brookings, SD—Twin Cities line.

A. Pages 4.36 to 4.40 of the Petition discuss community service reliability for the Brookings, SD—Twin Cities line. The Brookings, SD—Twin Cities line will provide some community service reliability benefits to the regions near the line. However, the Applicants were unable to quantify the size of the community service reliability needs in the areas.

From the Applicants' discussion, it is clear that there are some avoided cost benefits (for example, of 115 kV lines, transformers, etc) for community service reliability which should be credited to the Applicants' proposal in any comparative economic analysis. For example, on pages 4.39 to 4.40 the Petition states "without the addition of the proposed 345/115 kV transformation at Lake Marion Substation, 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." However, I chose to take an approach which places more burden on the Applicants, so I do not include these benefits in my cost calculations directly. As a result, my analysis understates the benefits of the Applicants' proposal by an unknown amount.

In summary, I cannot draw any conclusions about the appropriateness of the size of the Brookings, SD—Twin Cities line in terms of meeting community service reliability needs. However, there are non-quantified community service reliability benefits to consider.

Q. Please provide your analysis of the appropriateness of the Applicants' proposed size in terms of system-wide growth.

A. For the Brookings, SD—Twin Cities line, page 6.50 of the Petition indicates that the proposed transmission facility would raise the generation export level by about 700 MW. For the Fargo, ND—Twin Cities line, Table 5.1A on page 25 of Appendix A-3 of the Petition lists a North Dakota export (NDEX) increase of 350 MW for the project alone or an increase of 550 MW considering the combination of the proposed Fargo, ND—Twin Cities line, the proposed Bemidji—Grand Rapids 230 kV line (See Docket No. E015 et al/CN-07-1222), and other improvements. Thus, using the values reported by the Applicants the proposed lines would allow for an increase of about 1,050 MW to 1,250 MW in additional generation export capability. If there is a more appropriate measure of the added generation export capability created by the proposed transmission facilities, it would be useful for the Applicants to provide that measure in rebuttal testimony.

System-wide growth is discussed in Chapter 6 and Appendix A-1 of the Petition. The overall claimed need is to address between 4,500 and 6,300 MW of growth between 2009 and 2020.[6] Assuming the claimed need and my 1,050 MW to 1,250 MW calculation that are the case, then the proposed transmission lines, in terms of size, may be too small. The study related to regional issues, the *CapX 2020 Technical Update:*

[6] See pages 6.2 to 6.3 of the Petition.

Identifying Minnesota's Electric Transmission Infrastructure Needs, studied different combinations of quantities and locations of generation. All of the proposed transmission lines appeared as solutions in multiple scenarios; see also Figure 6-32 on page 6.39 of the Petition for a list of the common recommended facilities. Most likely both renewable and non-renewable generation will be needed to resolve the system-wide growth issue. Thus, exploration of alternatives that allow for greater potential access to renewable and non-renewable generation (i.e., an increase in size for the Fargo, ND—Twin Cities and Brookings, SD—Twin Cities lines) appears to be warranted.

While the Twin Cities—La Crosse, WI line may increase the potential for renewable generation resources to be delivered from southeastern Minnesota, the underlying transmission study provided in the Petition states (at page 162 of Appendix A-2) "These analyses [of the Twin Cities—La Crosse, WI line] were performed based solely on load serving issues.

Q. Do you conclude that Applicants' claimed size of the need is reasonable?

A. I did not analyze the Applicants' claims regarding the size of the need. Mr. Ham provides the OES's analysis of the claimed needs. Instead, I took the approach of taking the claimed need as a given and analyzing the alternatives in terms of meeting the claimed need. This is the same approach that has been followed by the OES in its alternatives analysis for several years.

Q. Please provide your analysis of the appropriateness of the Applicants' proposed size in terms of generation outlet/renewable energy support.

A. Using the values reported by the Applicants the proposed lines would allow for an increase of about 1,050 to 1,250 MW in additional generation export capability in regions with quality wind resources. This level can be compared to the need of several thousand MW of renewable and non-renewable resources estimated by OES witnesses Ms. Peirce and Mr. Ham. Therefore, I conclude that the proposed transmission lines, in terms of size, may be too small because the increase in generation export is significantly less than the claimed 4,500 MW to 6,300 MW need. Thus, exploration of alternatives that allow for greater potential access to renewables and non-renewables (i.e., an increase in size for the Fargo, ND—Twin Cities and Brookings, SD—Twin Cities lines) is warranted. However, I note that the proper forum for meeting the entire renewable need is the RES Report.

Q. Please summarize your analysis of the appropriateness of the Applicants' proposed size for the three main transmission lines proposed in this docket.

A. In general the Applicants' proposed size is reasonable. However, exploration of an increase in size for the Fargo, ND—Twin Cities and Brookings, SD—Twin Cities lines is warranted based upon the renewable generation interconnection and system-wide growth needs. While an increased size might be considered as "too big" in terms of meeting solely the community service reliability need, the proposed lines must be sized large enough to meet all of the claimed needs. As explained above, the Fargo—Twin Cities and Brookings—Twin Cities lines appear to be too small in terms of the claimed system-wide growth and generation outlet needs. Therefore, exploration of an increase in size for the Fargo—Twin Cities and Brookings—Twin Cities lines is warranted. It is my understanding that the next largest transmission line size that is commercially available beyond the 345 kV proposed for the Fargo-Twin cities and Brookings-Twin Cities lines is a 500 kV size.

2. Type Analysis

Q. Please provide your analysis of the Applicants' proposed transmission type.

A. I focused my analysis of type on two items, the type of cable selected for the proposed transmission facilities and the nature of the power (AC versus DC).

Q. Please provide your analysis of the cable selected.

A. OES Information Request No. 2 requested the Applicants to provide the justification for the proposed conductors (bundled conductor 954 ACSS cables for 345 kV lines and single conductor 795 ACSS cable for 230 kV and 161 kV lines). The Applicants' response was the size of conductors has become standardized by Xcel since the 1990s to reduce life-cycle costs. The Applicants' response also explained the selection of conductors for each project specifically. 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. For the 230 kV lines, use of the proposed conductor is consistent with the other 230 kV lines in the area. For the 161 kV lines, the proposed conductor is necessary to provide system support in the event of a 345 kV line outage.

In addition, North American Water Office (NAWO) and Institute for Local Self-reliance (ILSR) (jointly NAWO-ILSR) Information Request No. 5 requested information regarding the use of aluminum shunts "as an alternative to replace or delay the need for the proposed CAPX2020 lines." The Applicants responded that:

> this technique is not viable to replace or delay the need for the three 345 kV Projects. With the exception of some older lines, transmission lines in the state of Minnesota are designed to use the full capacity of the conductor and are not limited by the compression connector or any other hardware used in construction of the line.

The response proceeds to provide further information on this topic.

Finally, NAWO-ILSR Information Request No. 6 requested information regarding the use of Aluminum Conductor Composite Reinforced (ACCR) "as an alternative to replace or delay the need for the proposed CAPX2020 lines." The Applicants responded that:

> Reconductoring, using the ACCR conductor or any other type of conductor, is an improvement that can address overloads on individual lines…Planning engineers have concluded that reconductoring is not a means for addressing the generation outlet capability and increased load and regional reliability needs identified in the Application.

The response proceeds to provide further information on this topic.

Based upon the Applicants' response to OES Information Request No. 2 and NAWO-ILSR Information Request Nos. 5 and 6, I conclude that the Applicants proposed conductors are reasonable.

Q. Please provide your analysis of AC versus DC.

A. The Applicants explain the selection of AC over DC on pages 7.25 and 7.26 of the Petition. The Applicants selected AC over DC based upon cost considerations. In essence, the number of substations that the proposed transmission lines must connect with makes a DC configuration cost-prohibitive. The Applicants estimated the cost of a DC configuration for the entire project at $9.7 billion versus their proposed estimated total of $1.39 to 1.69 billion[7] for the entire project as proposed. Therefore, I conclude that the Applicants proposed nature of the power (AC) is reasonable.

3. Timing Analysis

Q. Please summarize the Applicants' proposed timing.

A. Page 2.16 of the Petition indicates that the Applicants' proposed timing is as follows:

- For the Twin Cities—La Crosse, WI project:
  - Rochester area 161 kV improvements by the end of 2011;
  - remainder of the project by the end of 2015;
- For the Fargo, ND—Twin Cities project:
  - Monticello to St. Cloud segment by the end of 2011;
  - St. Cloud to Alexandria segment by the end of 2013;
  - remainder of the project by the end of 2015;
- For the Brookings, SD—Twin Cities project:
  - Brookings, SD to Helena (a substation in Minnesota) segment by the end of 2013; and
  - Remainder of the project by the end of 2014.

All of these dates assume that the permitting process is completed by the end of 2010.

[7] See Figure 1-10 of the Petition.

Q. Please provide your analysis of the proposed timing of the Twin Cities—La Crosse, WI line.

A. The Twin Cities—La Crosse, WI line is being constructed with the 161 kV lines in the Rochester region first (in 2011) and the 345 kV line being completed later (in 2015). This approach would place greatest emphasis on addressing the Rochester community's service reliability need. While it would be useful for the La Crosse, WI area to receive improvements earlier, based upon a comparison of Figures 4-8 and 4-3 it appears that, in 2011, the Rochester area has a greater need than the La Crosse, WI area. Thus, I conclude that the Applicants' proposed timing for the Twin Cities—La Crosse, WI project is reasonable.

Q. Please provide your analysis of the proposed timing of the Fargo, ND—Twin Cities line.

A. The Fargo, ND—Twin Cities line is being constructed from southeast to northwest, see page 4.36 of the Petition. Overall, for this line it appears that the community service reliability need is of greater importance than the other needs. The Applicants' proposed construction plan places greatest emphasis on addressing the community service reliability needs in the St. Cloud area first and then progressing on to the needs in Alexandria and Fargo, ND. For the Fargo, ND—Twin Cities line, addressing the community service reliability needs in the sequence proposed by the Applicants is reasonable. Thus, I conclude that the Applicants' proposed timing for the Fargo, ND—Twin Cities project is reasonable.

Q. Please provide your analysis of the proposed timing of the Brookings, SD—Twin Cities line.

A. The Brookings, SD—Twin Cities line is being constructed west to east, see page 4.40 of the Petition. It appears that this construction plan would accelerate at least some of the increase in generation outlet while leaving the portion of the line which addresses community service reliability until later. Given the timing of the generation outlet and community service reliability needs, I conclude that the Applicants' proposed timing for the Brookings, SD—Twin Cities project is reasonable.

4. Summary of Size, Type, and Timing

Q. Please summarize your analysis of the Applicants' proposed size, type, and timing.

A. Based upon the above analysis, I conclude that the criterion established by Minnesota Rules 7849.0120 B (1) has been met. However, exploration of alternatives of greater size for the Fargo, ND—Twin Cities line and the Brookings, SD—Twin Cities line is warranted.

B. ALTERNATIVES ANALYSIS

1. Non-CN Alternatives

Q. What criterion do you consider in terms of non-CN alternatives?

A. Minnesota Rules 7849.0120 A (4) states that the Commission is to consider "the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand."

Q. Please list the non-CN alternatives.

A. Alternatives not requiring certificates of need could be generation facilities not requiring a CN under Minnesota Statutes §216B.2421, subd. 2 (1) (e.g., DG) or transmission facilities not requiring a CN under Minnesota Statutes §216B.2421, subd. 2 (2) and (3). I discuss each of these two categories of non-CN alternatives below.

a. Generation

Q. Please provide your analysis of generation-based, non-CN alternatives to the proposed facilities.

A. I begin by noting that Minnesota Statutes §216B.2426 states that:

> 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.

The definition in Minnesota Statutes §216B.169 is as follows:

> Subdivision 1 (c) "High-efficiency, low-emissions, distributed generation" means 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.

For CapX as a whole, the option of using additional generation as an alternative to the proposed transmission project is addressed on pages 7.12 to 7.15 of the Petition. The conclusions in the Petition were that:

1. the need to bolster the region's overall transmission system reliability "cannot reasonably be satisfied by installing additional local generation without transmission;"

2. for the need to provide additional generation outlet "generation in place of transmission cannot satisfy this need;"

3. the need for community service reliability improvements could be addressed by local generation, but there are significant obstacles such as the quantity and cost of generation required, the higher operations and maintenance costs, and the need for transmission to interconnect the generation.

Also, I note the conclusion on pate 7.24 of the Petition that dispersed wind by itself cannot address community service reliability.

Q. Did the Applicants look at generation as an alternative to each project separately?

A. For the Twin Cities—La Crosse, WI project, additional generation was addressed on page 34 of Appendix A-2 in Volume 1 of the Petition, filed August 16, 2007, which relies upon a consultant's study which concluded that additional generation (a 50 MW combustion turbine) should be built a decade earlier than the capacity is needed "to mitigate transmission outage risk during the approval process." That is, the Petition concludes that generation could not reasonably replace transmission for the long run but should be accelerated in the short run while transmission is permitted and constructed.

For the Fargo, ND—Twin Cities project, the transmission study provided in Appendix A-3 of the Petition built upon earlier work and did not consider additional generation. I recommend that the Applicants explain, in rebuttal testimony, why generation was not considered as an alternative to the Fargo, ND—Twin Cities project.

For the Brookings, SD—Twin Cities project, the primary need driver is generation outlet. Dispersed generation is a potential alternative to new transmission.

Such a strategy is being studied in two phases, as discussed on page 6.45 of the Petition. A first phase is looking at distributing 600 MW of distributed generation (DG) across Minnesota (this study phase is due June 2008) and a second phase is looking at distributing an additional 600 MW of DG across Minnesota (this study phase is due September 2009). However, even if these studies find suitable, cost-effective locations for the entire 1,200 MW of DG being studied, there certainly is no guarantee that such locations would be able to be configured to be right next to the load that the DG is to serve (for example, it is more difficult to locate DG facilities in each urban neighborhood where the demand for electricity has been growing in Minnesota). Thus, the generation outlet that would be created by the proposed transmission lines would still need to be addressed.

Further, interconnection is only one of the needs proposed to be filled by the proposed Brookings, SD—Twin Cities line. The project would also have some unquantified community service reliability benefits by providing more transmission capacity and would ease routing issues in the south metro area by providing a transmission source south of load, allowing new lines to be routed through sparsely populated areas rather than through the highly populated suburban areas. In other words, this alternative does not pass the screening test because it would not meet all of the same needs proposed to be met by the transmission lines.

Q. What is your conclusion based upon this information?

A. I conclude that non-CN generation cannot address the scope of the needs that would be addressed by the CapX proposal (community service reliability in numerous regions, strengthening the regional reliability in the North Dakota—Minnesota border region, and creating additional generation outlet capability in areas with high quality wind resources). However, if another party proposes a non-CN generation alternative in rebuttal testimony in this proceeding, I will review any such proposal and comment as time allows.

b. Transmission

Q. Please provide your analysis of transmission-based, non-CN alternatives.

A. One method for implementing a non-CN transmission alternative would be to reconductor existing transmission facilities. NAWO-ILSR Information Request No. 6 (also discussed above) requested information regarding reconductoring. The Applicants response was as follows:

- for the Fargo, ND—Twin Cities 345 kV line as a result of reconductoring "there would be no increase in the system's injection capability and no improvements to low voltages would be recognized;"
- For the Brookings, SD—Twin Cities 345 kV project "reconductoring is not a viable option;" and
- For the Twin Cities—La Crosse 345 k V project "reconductoring is not a viable option."

Q. What do you conclude, based on the above?

A. This response indicates that Fargo-Twin Cities reconductoring would not be sufficient to meet the needs proposed to be met in this proceeding. Regarding the statements that "reconductoring is not a viable option" for two parts of the proposal, I note that OES

Information Request No. 24 requested further data on the reconductor option for the transmission study underlying the Brookings, SD—Twin Cities line. The response stated that several lines would be overloaded under such an approach by more than 200 percent of their ratings. The response continued by stating that reconductoring is typically not an option if the overload exceeds 200 percent. Therefore, I conclude that transmission-based, non-CN alternatives are not a reasonable alternative to the proposed projects.

c. Summary

Q. Please summarize your analysis of non-CN alternatives.

A. I conclude that neither DG nor transmission facilities not requiring a CN are viable alternatives to the proposed facilities.

2. Screening Analysis

Q. What criterion do you consider in terms of size, type, and timing of the Applicants' proposed Project?

A. Minnesota Rules 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."

Q. What alternatives do Minnesota Rules require the Applicants to discuss?

A. Minnesota Rules part 7849.0260, subpart B requires a discussion of the availability of the following alternatives:

(1) new generation of various technologies, sizes, and fuel types;

(2) upgrading of existing transmission lines or existing generating facilities;

(3) transmission lines with different design voltages or with different numbers, sizes, and types of conductors;

(4) transmission lines with different terminals or substations;

(5) double circuiting of existing transmission lines;

(6) if the proposed facility is for DC (AC) transmission, an AC (DC) transmission line;

(7) if the proposed facility is for overhead (underground) transmission, an underground (overhead) transmission line; and

(8) any reasonable combinations of the alternatives listed in subitems (1) to (7).

Q. Please list the alternatives considered by the Applicants in their screening analysis.

A. Chapter 7 of the Petition discusses several alternatives:

- alternative system configurations:
  - upgrade of 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; and
- no build.

Q. Please provide your screening analysis of higher voltages.

A. The Applicants discuss higher voltages on pages 7.3 to 7.6 of the Petition. For the Fargo, ND—Twin Cities and Twin Cities—La Crosse, WI lines, the Applicants explain that higher voltages could be used, but that there would be fewer intermediate stops along the way resulting in a lesser improvement in community service reliability. Instead the line would focus on generation outlet. It appears that the Brookings, SD—Twin Cities line may face a similar community service reliability versus generation outlet trade off—see page 7.5 of the Petition. In addition, the underlying system may require strengthening before the outlet of a 500 kV alternative could be realized.

In summary, the Applicants' screening analysis explains that there is a trade off between community service reliability and generation outlet.

Q. How do you respond to this assumption?

A. I note, first, that both community service reliability and generation outlet are important. However, while such a trade off may exist it is not clear that there is a direct trade-off such that a 500 kV line means there must be fewer intermediate substations than would exist with a lower kV line. Rather, any trade off appears to be more a matter of cost, project design, and avoided losses than engineering necessity. Nonetheless, I believe that the generation outlet needs presented in this docket, whether calculated by the OES or the Applicants, are both significant and still understate the scale of the overall need for generator interconnection. The reason why I conclude an understatement exists is that the calculations do not consider the carbon ramp-down goals of Minnesota Statutes §216H.02 and/or the reaction of utilities to future carbon costs, as I discuss below.

Q. Do you have any other observations regarding the Applicants' analysis on this point?

A. Yes. I note that the engineering assumption that higher kV lines necessitate fewer substations appears to be part of the utilities' long-term trend of over-valuing capital expenditures and under-valuing energy loss considerations. See the OES's January 15, 2008 comments in Docket No. E999/M-07-1028 for further details (the relevant pages are provided in OES Exhibit No. ___ (SRR-19)).

Q. How does this proceeding guard against the utilities' long-term trend of over-valuing capital expenditures, given that the applicants are proposing capital expenditures?

A. The focus on this entire proceeding is to determine whether Applicants have adequately justified the need for the proposed facilities. Thus, examining the need, looking at reasonable alternatives, assessing the effects of the RES and so forth are all intended to ensure that these requested resources are needed and reasonable in providing electric service.

Q. Please explain how the carbon ramp-down goals of Minnesota Statutes §216H.02 and the reaction to carbon costs are relevant to this proceeding.

A. The goal of taxing carbon, either directly through a tax or indirectly through cap-and-trade, is not necessarily to raise revenue but to decrease carbon emissions. If significant carbon reductions are the desired goal, then existing, carbon-intensive generation (such as coal plants) will have to shut down and be replaced.[8]

For example, according the *Minnesota Utility Data Book*[9], Xcel obtained about 12.4 million MWh from Xcel's share of Sherco 1, 2, and 3. An existing coal plant can be expected to produce roughly 1 ton of CO_2 per MWh. Thus, for Xcel the Sherco facility can be assumed to result in about 12.4 million tons of CO_2 released annually.

OES Exhibit No. ___ (SRR-5) compares the state's CO_2 ramp-down goals for Xcel to Sherco's CO_2 footprint. The comparison shows that as early as 2013 Sherco alone consumes half of Xcel's CO_2 allotment under the state's goal, as applied to Xcel's system. Based upon this calculation, if the cap's goals are to be met or are representative of what must happen as an economic response to CO_2 costs, Xcel's existing coal-fired facilities are going to have to be replaced with less- CO_2 intensive resources, perhaps within the time frame considered in this proceeding.

Xcel, with large nuclear facilities at Monticello and Prairie Island and hydro from Manitoba and elsewhere, is not the most coal-intensive or carbon-intensive utility serving Minnesota customers. Therefore, this issue is likely to be even more significant for other utilities. For example, Dairyland Power Cooperative (DPC) estimated that DPC's CO_2

[8] Of course, cost-effective technology could be developed to capture and store CO_2, but I am not aware of sites to store CO_2 in Minnesota at a utility scale.
[9] Available at: http://www.state.mn.us/mn/externalDocs/Commerce/Utility_Data_Book,_1965-2000__030603120425_UtilityDataBook65thru05.pdf

emissions in 2005 were about 4.98 million tons (See DPC's response to OES Information Request No. 1 in Docket No. ET3/RP-08-113). DPC's largest coal-fired resources are John P Madgett (about 400 MW summer) and Genoa (about 356 MW summer) stations; note that about half of the Genoa facility is sold by DPC to GRE. Using DPC's allotment of those two generators (400 MW + (356 MW – 172 MW to GRE)), an estimate of one ton CO_2 per MWh emission, and an estimated 80 percent capacity factor results in about 4.1 million tons of CO_2 emissions annually. In other words, to ramp down CO_2, either in reaction to CO_2 prices or a government mandated emissions reduction, DPC would have to shut down existing coal units fairly soon after implementation of a tax or cap-and-trade system.[10] Additionally, while Minnesota Power declared the level of CO_2 emissions in 2005 to be trade secret, the end result is similar to that of Xcel; that is, the largest two or three units immediately produce a very significant level of CO_2 in terms of the entire CO_2 cap.

For now, while natural gas combined cycle units located at existing coal sites would be a logical alternative for utilities to consider to replace these coal facilities, Xcel's existing system already has significant natural gas generation, both in terms of energy and capacity. Further, Xcel's proposed expansion plan (see Xcel's filing in Docket No. E002/RP-07-1572) is already tilted towards obtaining a larger share of energy needs from natural gas. It is unlikely that all of the natural gas capacity could be used and still meet the CO_2 ramp down goals if additional natural gas capacity were also added as coal replacement. That leaves wind combined with other renewables as a logical replacement source for existing coal units. While other utilities used as an

[10] While redispatch can delay the need, there are limits to redispatching.

example do not use as much natural gas capacity, there are limits to the amount of natural gas generation they could add and still meet the overall ramp down goals, too.

A capacity expansion model such as Strategist can best determine the timing of such generating unit shut downs and the best replacement. The point of the instant proceeding is not to determine the need for and timing of such events but to plan and permit a transmission system that can adapt if and when such events occur. Most importantly this must be done in a timely manner.

Q. How could the proposed transmission projects in this proceeding help address carbon ramp-down goals?

A. In general, greater access to renewable resources such as wind power and hydro power would give utilities greater ability to meet carbon ramp-down goals. The Fargo, ND—Twin Cities and Brookings, SD—Twin Cities projects improve access to high quality renewable resources in western Minnesota, eastern South Dakota, eastern North Dakota, and potentially Manitoba with future transmission improvements. While Applicants' proposal for this facility is a start in the right direction, I conclude that exploration of pre-building both lines to a higher (500 kV) voltage is warranted.

Q. Why is it important to explore this issue in this proceeding?

A. It can take a decade or more for a transmission project the size of CapX to move from engineering study through permitting and construction to in-service.[11] Therefore, as a matter of policy it is important to take full advantage of the proposals before the

[11] Compare the October 2005 date for the engineering study in Appendix A-1 of the Petition to the 2015 on-line date for the last of the proposed projects. Further note that the study in Appendix A-1 of the Petition built upon prior studies initiated before 2005.

Commission now and if warranted, permit the lines to the size required today while allowing the facilities to adapt to future needs that are reasonably foreseeable at this time. That is the fundamental justification for exploring a 500 kV build for the Brookings, SD—Twin Cities and Fargo, ND—Twin Cities lines. This alternative is discussed further below.

Q. How does this analysis compare to OES witness Mr. Ham's need analysis?

A. Mr. Ham's need analysis is, quite properly, based upon the Applicants' claims. I am not claiming that these calculations should be part of the overall need analysis in this docket. Rather, the policy impacts on the alternatives analysis of other, potentially large needs in the future should be considered now, to the extent we can do so. This discussion is intended to illustrate potential size and timing impacts of a policy of reducing CO_2 on existing generation and thus the transmission system and guide the alternatives available in this docket.

Q. Please provide your screening analysis of lower voltages.

A. The Applicants discuss lower voltages on pages 7.6 to 7.7 of the Petition. Lower voltage lines were rejected because:

- they are inadequate to address some of the community service reliability needs in the long run; and
- they have higher losses and thus are less efficient for the long-distance transmission needs that must be addressed.

I agree with the Applicants' analysis that lower voltages lines would be inefficient and unable to address the needs during the long run. Therefore, I conclude that lower voltage lines generally do not need to be explored further. However, below I do provide an economic comparison of the Twin Cities—La Crosse line to a 161 kV alternative to demonstrate more clearly the issues involved with the use of lower voltage lines.

Q. Please provide your screening analysis of alternative substations.

A. The Applicants' process for selecting substations was lengthy, detailed, and documented both in Chapter 5 and in the associated transmission studies provided in Appendices A-1 to A-4 of the Petition. From this analysis, it is clear that an alternative configuration is viable. I review alternative configurations further below.

Q. Please provide your screening analysis of double circuiting.

A. The Applicants discuss double circuiting on pages 7.8 to 7.12 of the Petition. For all three projects double circuiting is a potential option. Many of the double circuiting options are, in essence, routing alternatives—aligning the route for the proposed line with previously existing lines. Such alternatives will be considered during routing proceedings. For purposes of the CN, the Applicants proposed that the Brookings, SD—Twin Cities line be double circuited between the Lyon County and Helena substations. I conclude that the Applicants have adequately explored double circuiting the proposed transmission lines.

Q. Please provide your screening analysis of generation alternatives.

A. Generation alternatives not requiring a CN were discussed previously in response to a question regarding generation-based, non-CN alternatives. The same basic analysis would apply to generation alternatives that would require a CN. That is, I conclude that generation alternatives would not be viable to meet the needs of bolstering the region's overall transmission system reliability, providing generation outlet, and improving reliability of community service. Moreover, I note that the generation outlet needs presented in this docket, whether calculated by the OES or the Applicants, even though significant, understate the scale of the overall need for generator interconnection since the carbon ramp-down goals of Minnesota Statutes §216H.02 and/or the reaction of utilities to future carbon costs are not fully incorporated.

Q. Did the OES perform an engineering analysis of the proposed alternatives?

A. No, although knowledgeable entities other than the Applicants have done so and will do so in the future. The Applicants' response to OES Information Request No. 27 explains that the engineering studies presented in Appendices A-1 to A-4 have been peer reviewed multiple times. First, the engineering studies were presented to Mid-continent Area Power Pool's (MAPP) Missouri Basin SPG and Northern MAPP SPG multiple times. The SPG meetings are open to the public. Second, the Midwest Independent Transmission System Operator (MISO) reviews the transmission plans, including power flow study work and examines the assumptions. I understand that MISO is currently reviewing the projects. Therefore, I conclude that the proposed projects have been and will be subject to peer review of engineering in two forums, and that an appropriate focus of the CN process is on social impacts, economic impacts, and state policy goals.

3. Development of Cost Values

Q. Please explain how you developed the cost values used in your analysis of alternatives.

A. I developed five different cost values:

- The internal cost of energy losses;
- The external (or environmental) cost of energy losses;
- The cost of demand losses;
- The cost of capital; and
- The operation and maintenance cost.

Q. Why do you conclude that the three costs of losses should be applied to transmission lines?

A. First, when electric capacity is provided to the system by a power plant but capacity produced by this resource is dissipated as heat during transmission, those capacity losses impose a cost upon the system which must be accounted for. That is a power plant must be built larger to compensate for what is lost as heat in transmission. Second, when electric energy is produced but is dissipated as heat during transmission, those energy losses also impose a cost upon the system which must be accounted for. Again, additional energy must be produced to provide the energy lost as heat in transmission. Third, it is commonly understood that there is a cost of pollution associated with energy production. Similarly, in the case of a transmission line, if alternative 1 has greater (energy) line losses than alternative 2, then alternative 1 causes the system to produce more energy, burn more fuel to produce the additional energy, and thus cause the release of additional pollutants. Therefore, energy losses should be valued both for the cost of the energy itself and for the cost of pollutants.

Q. Can you explain how you will be using real and nominal values?

A. Yes, see OES Exhibit No. ___ (SRR-6) which contains 2 pages from the November 17, 2006 *Direct Testimony of Stephen Rakow* in Docket No. E017, et. al./CN-05-619 explaining the concepts of real and nominal as they apply to the data at hand. Specifically, this exhibit is intended to highlight the question and answer beginning on line 15 of page 41 provided in OES Exhibit No. ___ (SRR-6).

a. Capital Cost

Q. Please explain how you developed a value for the capital cost.

A. I begin by noting that the capital costs provided by the Applicants are in the form of an up-front capital cost. However, as explained below, the transmission losses will be incurred on an annual basis. Therefore, to have a common format, I present the costs in present-value form. Since public power and investor-owned applicants have distinctly different discount rates, the calculation of the present value of the costs must be done separately for each class of Applicant.

I use the following process to arrive at the present-value cost of capital invested. First, I determine the annual revenue requirement for a $1 million investment[12] by multiplying $1 million by a fixed charge rate for transmission facilities for each class of Applicant. Based upon the information provided in the Big Stone 2 proceeding [See my November 17, 2006 Direct Exhibits at DOC Exhibit No. ___ (SRR-4) that are included here as **Trade Secret** Exhibit No. ___ (SRR-20) due to potential trade secret issues with entities that are not parties to this proceeding], 7.7 percent would be a typical fixed charge rate for transmission for public power utilities while 12.75 percent would be a typical fixed charge rate for transmission for investor-owned utilities. As explained below, I use a range of 7.7 (all public power) to 12.75 percent (all investor-owned) with a value of 11.2 percent for the estimated ownership structure (the weighted average).

Second, I calculate the present value of the annual revenue requirement by multiplying the annual revenue requirement by a present value formula. Based upon the information provided in the Big Stone 2 proceeding [See my November 17, 2006 Direct Exhibits at DOC Exhibit No. ___ (SRR-4) that are included here as **Trade Secret** Exhibit No. ___ (SRR-20)], I use a 35-year life for the transmission facilities, and a discount rate range of 5.5 percent (all public power) to 7.6 percent (all investor owned) with a value of 7.0 percent for the estimated ownership structure (the weighted average). Thus, the present value of the annual revenue requirement per million dollars is between $1.19 million and $1.55 million with $1.45 representing the present value of the annual revenue requirement per million dollars of investment cost for the estimated ownership structure. See OES Exhibit No. ___ (SRR-7) for these calculations.

[12] Used only to derive the present value cost formula.

b. Cost of Demand Losses

Q. Please explain how you calculated the cost of demand losses.

A. I used the following process to calculate the cost of the demand losses. First, I added the 15 percent required reserve ratio to an assumed one MW of demand loss to determine the capacity that would be required to replace each MW of demand losses. The 15 percent required reserve ratio may be decreased to 14.2 percent in the near future; see Xcel's March 4, 2008 response to Joint Intervenor Information Request No. 4 in Docket No. E002/RP-07-1572. However, that change has not yet been approved. Further, it is not clear which utilities will use the new 14.2 percent ratio if it is approved. Therefore, I use 15 percent in my calculations.

Second, I determined the installed cost of one MW of demand loss. In essence this is the capital cost of the power plant that would replace the one MW of demand loss. The question is, what type of power plant is replacing the loss? Given the current prohibitions of Minnesota Statute §216H.03 subd. 3[13] and recent announcements regarding baseload unit acquisition by Xcel and Minnesota Power, I conclude that a mixture of 50 percent combustion turbines (CT) and 50 percent combined cycle (CC) facilities is a reasonable approximation. Based upon experience in recent CN and resource planning dockets,[14] a cost of $600 per kW is reasonable for CTs and a cost of $1,200 per kW is reasonable for CCs. Thus, the average cost per kW lost is $900[15] x 1.15 or $1,035 ($1.035 million per MW lost).

[13] This statute prohibits construction within the state, importing energy to the state, or signing a purchase agreement with a new large energy facility that would contribute to statewide power sector carbon dioxide emissions. Exemptions are provided for certain types of facilities.
[14] For example, E017 et al/CN-05-619; ET2/CN-07-678; E002/RP-07-1572; and E015/RP-07-1357.
[15] Calculated as (0.50 x 600) + (0.50 x 1,200).

Third, I determined the annual revenue requirement associated with the installed cost by multiplying the installed cost of $1.035 million per MW from step two by a fixed charge rate for generation facilities. Based upon the information provided in the Big Stone 2 proceeding [See my November 17, 2006 Direct Exhibits at DOC Exhibit No. ___ (SRR-4) that are included here as **Trade Secret** Exhibit No. ___ (SRR-20)], 7.7 percent would be a typical fixed charge rate for generation for public power utilities while 12.5 percent would be a typical fixed charge rate for generation for investor-owned utilities. Therefore, as explained above, I use a range of 7.7 (all public power) to 12.5 percent (all investor-owned) with a value of 11.0 percent for the estimated ownership structure (the weighted average). Thus, the annual revenue requirement per MW lost is between $80,000 and $129,000 with $114,000 representing the annual revenue requirement per MW lost for the estimated ownership structure. See OES Exhibit No. ___ (SRR-8) for these calculations.

Fourth, I determined the present value of the cost of each MW of demand losses by multiplying the annual revenue requirement by a present value formula. Based upon the information provided in the Big Stone 2 proceeding [See my November 17, 2006 Direct Exhibits at DOC Exhibit No. ___ (SRR-4) that are included here as **Trade Secret** Exhibit No. ___ (SRR-20)], I use a 35-year life for the transmission facilities, and a discount rate range of 5.5 percent (all public power) to 7.6 percent (all investor owned) with a value of 7.0 percent for the estimated ownership structure (the weighted average). Thus, the present value of the annual revenue requirements per MW of demand losses is between $1.23 million and $1.57 million with $1.48 representing the present value of the annual revenue requirements per MW of demand losses for the estimated ownership structure. See OES Exhibit No. ___ (SRR-9) for these calculations.

c. Internal Cost of Energy Losses

Q. Please explain how you developed a value for the internal costs of energy losses.

A. The internal cost of annual energy losses is equal to the demand losses times a factor to translate demand into annual energy times the system's cost to acquire the additional energy, valued for the appropriate duration. The quantity of demand losses and the appropriate factor to translate demand into energy are based upon engineering studies and engineering judgment. They are typically provided in the relevant transmission study; I take these as fixed inputs.

The system's cost of additional energy and the term to consider for the losses are economic issues. Regarding the cost of energy, the Locational Marginal Price (LMP) in the MISO Day 2 Energy Market best represents the cost of energy losses since the LMP represents the cost of the last unit of energy consumed. There are three issues with the use of LMPs. First, LMPs vary by the hour and I do not know the hours during which the incremental losses occur. Therefore, I use an average of the LMPs for all hours. Second, it cannot be known which location's LMP is applicable to the losses since it is not known where the energy lost is produced. Therefore, I use the Minnesota Hub LMP, an LMP based upon the Twin Cities region.[16]

Finally, LMPs are available either on a day-ahead or real-time basis. In response to OES Information Request No. 28 the Applicants provided the day-ahead and real-time

[16] According to Platts, "As defined by the Midwest Independent Transmission System Operator (MISO), the Minnesota hub is comprised of approximately 170 nodes in and around the cities of Minneapolis and St. Paul, Minn."

LMPs for the Minnesota Hub for each hour from April 1, 2005 through March 31, 2007.[17] I averaged the hourly real-time and day-ahead LMPs for the full time period. The result was that the average day-ahead LMP was $47.40 while the average real-time LMP was $45.52. Thus, the day-ahead LMP was $1.88 (or 4.1 percent) higher than the corresponding real-time LMP. I conclude that the day-ahead price is reasonable to use since the premium reasonably reflects the uncertainty or risk inherent in forecasting such data.

To determine the actual value to use, I averaged the day-ahead LMP for all hours during 2007. I then inflated the 2007 average value by 2.5 percent to obtain 2008 dollars; the result was a cost of $53.22 per MWh.

Regarding the term of the losses, the most reasonable period to use is the lifetime of the asset. While it is true, as the Applicants state, that the structure of the transmission system and quantity of losses become uncertain far in the future, the appropriate issue is not whether the forecast is uncertain but what represents the best forecast of the current uncertainty. The Applicants use an estimate of $0 for losses after 20 years and provide no information whatsoever that $0 is a reasonable estimate.

The Applicants refer to the use of a shorter term analytical period as "conservative." I do not believe that use of a shorter term can be called conservative. The effect of such analysis is to consider the full impact of a decision on capital costs but only part of the impact of a decision on energy costs. Thus, using a shorter analytical period biases the analysis towards overvaluing capital expenditures and undervaluing energy losses. The impact of a decision on both capital costs and energy costs should be considered equally. Therefore, I use the same term for all loss calculations, 35 years.

[17] Due to the length of the response, the response is not included in OES Exhibit No. __ (SRR-2).

d. External Cost of Energy Losses

Q. Please explain how you developed a value for the external costs of energy losses.

A. Again, external costs are usually regarded as the emissions required to generated sufficient power to compensate for energy losses. There are two groups of pollutants to consider. One group consists of the pollutants that can be considered as external costs. Generally, these have an official externality cost determined by the Commission. The second group consists of the pollutants that can be considered as internal costs. They have, or in the case of greenhouse gases, (primarily CO_2) likely will have, a cost determined by the market. Based on the Commission's previous decisions, at that point, the market-determined price is expected to be the value the Commission would require to be used in these analyses. For those pollutants which already have an internal cost (through a cap-and-trade system or a pollution tax) the cost will be included in the LMP data that I used. Therefore, such pollutants do not need to be considered further. However, CO_2 does not yet have a market-based cost and, therefore, an internal cost for CO_2 is not included in the LMP data and an estimate of future (internal) CO_2 costs must be applied separately. I discuss this issue further below.

Q. Please explain the process you used for determining the cost of pollutants.

A. Regarding Commission-valued pollutants, the Commission has established externality values based upon a cost per ton of pollutant released. The most recently published values are available in the Commission's July 12, 2007 *Notice of Updated Environmental Externality Values* (Docket No. E999/CI-00-1636). These values are updated periodically for inflation; the last update issued by the Commission was for the period through 2006. The Commission has approved values for the following areas:

- urban;
- metropolitan fringe;
- rural; and
- within 200 miles of Minnesota.

The question then is which values to apply. As explained above, line losses are a system phenomenon since the analysis producing the loss estimates was based upon a system analysis. Thus, it is reasonable to assume that the additional energy necessary to make up the line losses comes from the electric system generally. However, if the electric system is the source of the make-up energy then it is not clear what externality values to apply nor is it clear what quantities of pollutants are released. In this case the Applicants' power plants are located in all areas. Thus, the use of the Metropolitan Fringe values is reasonable since that category represents a mid-point between the urban and rural externality values. These values are shown below in Table 1. Since the Commission's values are in 2006 dollars, I converted the Commission's values to 2008 dollars using an annual inflation rate of 2.5 percent to provide a consistent cost analysis. Both sets of values are shown in Table 1.

Table 1: Metropolitan Fringe Externality Values (Dollars per ton)

	2006 Dollars		2008 Dollars	
Pollutant	**Low**	**High**	**Low**	**High**
SO_2	$ -	$ -	$ -	$ -
PM10	$ 503.62	$ 3,636.36	$ 529.12	$ 3,820.45
CO	$ 0.96	$ 1.69	$ 1.01	$ 1.78
NO_x	$ 176.40	$ 335.16	$ 185.33	$ 352.13
Pb	$ 2,081.52	$ 2,513.70	$ 2,186.90	$ 2,640.96
CO_2	$ 0.38	$ 3.94	$ 0.40	$ 4.14

Further, the Commission has approved a value of \$4 to \$30 starting in 2012 to estimate the future internal cost of CO_2 (see Docket No. E999/CI-07-1199). However, I understand that the Commission-approved CO_2 values do not apply to this docket since the Petition was filed prior to the Commission's determination in Docket No. E999/CI-07-1199. Therefore, I referred to Docket No. E017 et al/CN-05-619 (the Big Stone 2 transmission proceeding) to find substitute values. The lowest value proposed by the Big Stone Unit II applicants[18] was \$6 per ton in 2006 dollars.[19] The highest value proposed by the Joint Interveners[20] was \$30.50 per ton in 2005 dollars.[21] Using these values and a 2.5 percent inflation rate I calculate a range of \$6.30 to \$32.85 per ton of CO_2 in 2008 dollars. Therefore, I use a low CO_2 cost value of \$6.30 per ton and a high CO_2 value of \$32.85 per ton.

Regarding pollutants without a Commission-approved value, Mercury (Hg) should be included in the analysis. The Commission's October 5, 2001 *Order Deferring Further Action on Quantifying Mercury and Particulates and Maintaining Purchased Power Policy* states at point 1:

> The Commission will defer any further consideration of adopting environmental cost ranges for mercury at least until the direction of the EPA rules is clear and until existing uncertainties are reduced sufficiently to allow a damage-cost analysis to be done. In the meantime, utilities should continue to consider the effects of mercury qualitatively in resource procurement proceedings before the Commission.

At this point it appears clear that Hg will have an internal cost in the near future; in fact some utilities have already included such costs in their resource planning

[18] At that time the Big Stone Unit II applicants were Otter Tail Power Company (OTP), Great River Energy (GRE), Missouri River Energy Services (MRES), Montana-Dakota Utilities Co. (MDU), Southern Minnesota Municipal Power Agency (SMMPA), Central Minnesota Municipal Power Agency (CMMPA), and Heartland Consumers Power District (HCPD).
[19] See the December 1, 2006 *Prefiled Rebuttal Direct Testimony of Thomas Hewson* at page 5, lines 9-11.
[20] The Joint Intervenors were: Izaak Walton League of America – Midwest Office, Fresh Energy, Wind on the Wires, Union of Concerned Scientists, and Minnesota Center for Environmental Advocacy.
[21] See the November 17, 2006 *Direct Testimony of David A. Schlissel and Anna Sommer* at page 25, line 6.

modeling. Regarding Hg pricing, the U. S. Energy Information Administration (EIA) has stated that "Allowance prices are expected to climb to a high of $68,000 per pound in 2030." See OES Exhibit No. ___ (SRR-10). To convert this estimate to a value reasonable to use in this proceeding I took the $68,000 per pound, multiplied by 2,000 to obtain dollars per ton, and then multiplied by 0.5 (for the low value) and 0.75 (for the high value) to account for the fact that the average cost will be less than EIA's highest cost estimate. This calculation results in a cost range of $68 million to $102 million per ton of Hg.

As shown in Table 1 above, the Commission has approved an externality value for NO_x as shown in the Table above. However, the EIA document provided in OES Exhibit No. ___ (SRR-10) indicates that "NO_X allowance prices are projected to range from $2,400 to $3,300 per ton." This estimated, market-based cost value for NO_X is substantially higher than the Commission-approved value. Since the EIA estimated cost is based upon more recent data I conclude that it is more likely to reflect the actual costs to be incurred and I use that value rather than the Commission-approved externality value. A summary of the pollution cost values discussed above is provided in Table 2.

Table 2: Pollution Cost Values
(2008 dollars per ton)

Pollutant	Low	High
PM10	$529	$3,820
CO	$1	$2
NO_x	$2,400	$3,300
Pb	$2,187	$2,641
CO_2	$6	$33
Hg	$68,000,000	$102,000,000

Q. The pollutant cost values are expressed in terms of dollars per ton. Please explain how you calculated the tons of emissions of the pollutants associated with the energy losses.

A. I obtained estimates of tons of emissions per MWh for the various pollutants from data provided by Xcel in Docket No. E002/RP-07-1572 from the Strategist model. The data represents average emissions in pounds per MWh during the period 2008-2047. The data is provided in Table 3 below. I note that the average value does not reflect current emission rates, but includes a substantial reduction (in pounds per MWh) for most of the pollutants during the 2008-2047 planning period.

Table 3: Pollutant Emissions
(pounds per MWh)

Pollutant	Emission Rate
PM10	0.184723
CO	0.246017
NOX	1.138579
PB	0.000057
CO2	1,541.875375
HG	0.000018

Q. Please explain how you used this data to calculate the total cost of pollution associated with energy losses.

A. I took the cost values in Table 2 above and multiplied by the emission rates in Table 3 above (converted to tons per MWh). The results are a range of $6.89 to $28.48 per MWh for pollution costs. This result is shown below in Table 4.

Table 4: Pollution Cost
(2008 dollars per MWh)

Pollutant	Cost Rate Low	Cost Rate High
PM10	$ 0.05	$ 0.35
CO	$ -	$ -
NO_x	$ 1.37	$ 1.88
Pb	$ -	$ -
CO_2	$ 4.86	$ 25.33
Hg	$ 0.61	$ 0.90
Total	$ 6.89	$ 28.46

e. Total Cost of Energy Losses

Q. Please explain how you calculated the total cost of energy losses.

A. The total cost is the LMP cost ($53.22) plus the pollution cost—external costs plus future internal costs not yet reflected in the LMP data ($6.89 to $28.46) for a final range of $60.10 to $81.68 per MWh in 2008 dollars. This range can be applied to the MW losses through use of an assumed load factor of the losses.

Page 53 of Appendix A-3 of the Petition indicates that the Applicants used a 41.5 percent load factor of the losses applied to the on-peak MW losses in the study underlying the Fargo, ND—Twin Cities line. Page 28 of Appendix A-4 of the Petition indicates that the Applicants used a 30 percent load factor of the losses applied to the off-peak MW losses in the study underlying the Brookings, SD—Twin Cities line. I note that the 41.5 percent/on-peak method appears to be backed by study work while the 30 percent/off-peak method appears to be an assumption. Therefore, to standardize the analysis and ensure that energy losses are not understated, I use the 41.5 percent load factor of the losses applied to the on-peak MW losses method. Thus, one MW of off-peak losses results in an annual energy cost (internal and external) of between $218,000 and $297,000.[22]

I determined the present value of the annual energy cost of each MW of demand losses by multiplying the annual revenue requirement by a present value formula. Based upon the information provided in the Big Stone 2 proceeding [See my November 17, 2006 Direct Exhibits at DOC Exhibit No. ___ (SRR-4) that are included here as **Trade Secret** Exhibit No. ___ (SRR-20)], I use a 35-year life for the transmission facilities, and a real discount rate range of 2.5 percent (all public power) to 4.6 percent (all investor owned) with a value of 4.0 percent for the estimated ownership structure (the weighted average). Thus, the present value of the annual revenue requirements for the energy cost associated with each MW of demand losses (using the low energy cost) is between $3.76 million and $5.05 million with $4.07 million representing the present value of the annual revenue requirements for the energy cost associated with each MW of demand losses for the estimated ownership structure. The present value of the annual revenue requirements for the energy cost associated with each MW of demand losses (using the high energy cost) is between $5.12 million and $6.87 million with $5.54 million representing the present value of the annual revenue requirements for the energy cost associated with each MW of demand losses for the estimated ownership structure. This result is summarized in Table 5 below. See OES Exhibit No. ___ (SRR-11) for these calculations.

Table 5: Present Value of Annual Energy Cost
(Million Dollars)

	Public Power	**Investor Owned**	**Weighted Average**
Low Energy Cost	$ 5.05	$ 3.76	$ 4.07
High Energy Cost	$ 6.87	$ 5.12	$ 5.54

[22] Calculated as 41.5 percent load factor times 8,760 hours per year times the energy cost per MWh ($60.10 or $81.68).

f. Operations and Maintenance Costs

Q. How did you value operations and maintenance (O&M) costs?

A. Regarding O&M costs, the Petition at page 9.17 states that "for voltages from 115 kV through 345 kV, past experience shows that costs are approximately $300 to $500 per mile." Thus, $300 to $500 represents the annual revenue requirement per mile for O&M costs. I determined the present value of the O&M cost for each mile of new transmission corridor by multiplying the annual revenue requirement by a present value formula for the expected life of the facility. Based upon the information provided in the Big Stone 2 proceeding [See my November 17, 2006 Direct Exhibits at DOC Exhibit No. ___ (SRR-4) that are included here as **Trade Secret** Exhibit No. ___ (SRR-20)], I use a 35-year life for the transmission facilities, and a real discount rate range of 2.5 percent (all public power) to 4.6 percent (all investor owned) with a value of 4.0 percent for the estimated ownership structure (the weighted average). Thus, the present value of the O&M cost for each mile of new transmission corridor, using the low end cost estimate, is between $5,200 and $6,900 with $5,600 representing the present value of the O&M cost for each mile of new transmission corridor for the estimated ownership structure. The present value of the O&M cost for each mile of new transmission corridor, using the high end cost estimate, is between $8,600 and $11,600 with $9,300 representing the present value of the O&M cost for each mile of new transmission corridor for the estimated ownership structure. See OES Exhibit No. ___ (SRR-12) for these calculations.

4. Cost Analysis of Alternatives

Q. Please provide an overview of the cost analysis of alternatives.

A. Overall, the cost analysis of alternatives is governed by Minnesota Rules 7849.0120 B which states that a certificate of need must be granted upon determining that:

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

The rule then proceeds to list criteria.

Q. What are the criteria that apply at this point in the analysis?

A. Minnesota Rules 7849.0120 B (2) states that the Commission is to consider "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." I interpret the "costs" noted above as referring to the internal costs which ratepayers would be subject to being charged for such resources. Also, Minnesota Rules 7849.0120 B (3) states that the Commission is to consider "the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives." I interpret this consideration as referring to the social (internal plus external) costs. To simplify the analysis, I cover both criteria by using my energy cost value which includes pollutant costs. While my approach is reasonable, a more detailed analysis would be to present all internal costs (for Minnesota Rules 7849.0120 B2) and all social costs (for Minnesota Rules 7849.0210 B3) separately. However, that detailed approach would necessitate splitting the pollutant costs into two groups, greatly increasing the complexity and length of the analysis.

a. Analysis of Configuration

Q. Please provide an overview of how you analyzed the Applicants' proposed configuration.

A. The Petition analyzed several potential configurations:

- Fargo, ND to Twin Cities line—three different substations on east end;
- Twin Cities to La Crosse, WI line—two different substations on east end and two different substations on the west end; and
- Brookings, SD to Twin Cities line—two configurations.

Since these choices can interact with each other, potentially there are 3 x 2 x 2 x 2 = 24 different configurations. To reduce the problem to manageable size I analyzed seven different scenarios by considering the configuration of each line separately. That is, I ignored system effects that variations in configuration of one line would have on other parts of the overall proposal.

Q. How do you address the fact that each of the three main lines, as proposed, terminates in an adjacent state?

A. For the termination points in neighboring states, the Commission's Order could name a substation in another state, a border crossing, or both. I conclude that naming a substation and citing the Applicants' proposed border crossing corridors would provide sufficient guidance for the subsequent routing docket.

Q. Did the Applicants use a consistent set of cost numbers for the proposed projects throughout the Petition?

A. No, there are differences in the cost estimates provided in the underlying transmission studies of Appendices A-2 to A-4 with the estimates provided in the main body of the Petition.

Q. Did you ask the Applicants to reconcile the differences between the cost estimates provided in Appendices A-2 to A-4 with the estimates provided in the main body of the Petition?

A. Yes, OES Information Request Nos. 18, 19, and 20 requested that the Applicants reconcile the differences between the cost estimates indicated in the Appendices A-2 to A-4 of the Petition with those provided in the main body of the Petition. The Applicants' response to each Request was the same:

> The initial cost figures were planning-level estimates produced in late 2005 or early 2006 for the purpose of screening alternatives in electrical performance analysis. Since that time, Xcel Energy has designed and begun construction of the Lakefield Junction to Split Rock 345 kV line. Data from this recent project was updated further and used to establish new estimates for the CapX2020 projects.
>
> The increase in estimated costs primarily can be attributed to: 1) actual design data from a recent, robustly designed 345 kV project and 2) recent significant cost increases in materials and labor necessary to construct these projects.

This response reasonably explains the different cost estimates and explains that the cost estimates in the main body of the Petition are the more reasonable estimates.

1) Fargo, ND—Twin Cities Line

Q. How did the Applicants select the southeastern termination point for the proposed Fargo—Twin Cities transmission line?

A. On the southeast end, the proposed Fargo—Twin Cities transmission line could terminate at either the Benton County, Sherburne County, or Monticello substations. The Petition states at page 5.18 that the Fargo, ND — Twin Cities 345 kV proposed configuration starts at the Monticello substation on the east end.

The Petition justifies the selection of the Monticello substation as follows. First, the Applicants rejected the Benton County Substation. Selection of the Benton County substation would result in a smaller increase in the load-serving capability in the St. Cloud area; only 284 MW for Benton County versus 320 MW for the Sherburne County and Monticello substations (see the Petition at page 5.17). Also, use of either the Sherburne County substation or the Monticello substation would provide a 345 kV source from the east which Benton County cannot do without additional 345 kV transmission (see the Petition at page 5.18).

Second, among the two remaining choices, the Monticello substation was chosen over the Sherburne County substation for two reasons. Monticello termination:

- would provide additional reliability improvements in the event of system disturbances; and
- would not require a Mississippi River crossing.

Q. How did you analyze the alternative system configurations for the proposed Fargo, ND—Twin Cities transmission line?

A. OES Information Request Nos. 29 and 30 requested the Applicants to provide the capital costs and line losses associated with the three potential termination points. The

Applicants' responses to OES Information Request Nos. 29 and 30 are summarized in Table 6 below.

Table 6: Fargo, ND—Twin Cities Line Termination Data

Termination	Cost (million $)	Losses
Benton County	$390 to $530	Similar
Sherburne County	$390 to $550	Similar
Monticello	$390 to $560	Similar

Using the data in Table 6 and the cost values provided earlier, the cost of each termination point can be calculated. Table 6 shows that the Sherburne County substation has an incremental cost of $0 to $20 million (over the Benton County substation), for a mid-point incremental cost of $10 million. Table 6 also shows that the Monticello substation has an incremental cost of $0 to $30 million (over the Benton County substation), for a mid-point incremental cost of $15 million. Using the cost range of between $1.19 million and $1.55 million with $1.45 million for the estimated ownership structure results in the Present Value of Revenue Requirements (PVRR) range represented in Table 7 below.[23]

Table 7: Cost of Fargo, ND—Twin Cities Alternatives[24]
(incremental PVRR in million dollars)

Termination	Low	Median	High
Benton County	$ -	$ -	$ -
Sherburne County	$ -	$ 14.50	$ 31.00
Monticello	$ -	$ 21.75	$ 46.50

Table 7 demonstrates that the Benton County alternative is the least cost choice. However, page 5.17 of the Petition states that the Benton County alternative provides substantially lower load-serving capabilities in the St. Cloud area. Specifically, the

[23] Adding 30 miles of additional corridor between Benton County and the Sherburne County/Monticello area (see page 5.17 of the Petition) would add between $0.16 million and $0.35 million for the PVRR of the O&M costs to the figures in Table 7. This amount is too small to consider further.

[24] Note that 'low' uses the low end of the Applicants' capital cost range and my cost range, 'high' uses the high end of the Applicants' capital cost range and my cost range, and 'median' uses the mid-point of the Applicants' capital cost range and my cost assuming the estimated ownership structure. The same definitions apply to subsequent tables.

Benton County termination provides 232 MW versus 320 MW for either the Sherburne County or Monticello alternatives. The Benton County load-serving capability can be raised to 284 MW by reconductoring a 30-mile length of 230 kV line (see page 5.17 of the Petition). 284 MW of capability is still substantially lower than the Sherburne County and Monticello alternatives and likely would eliminate the Benton County alternative's cost advantage.

The Sherburne County alternative costs, using the median figures, is about $7.25 million PVRR less than the Monticello alternative. The Petition at page 5.18 indicates that the Sherburne County alternative also has a marginally better load-serving capability than the Monticello alternative. The trade-off for the cost and load-serving advantage is that the Monticello alternative:

- would provide a reliable source for St. Cloud in the event of an outage of the Sherburne County 345 kV bus;
- would provide additional reliability improvements in the event of an extreme system disturbance; and
- would not require a Mississippi River crossing during routing.[25]

Finally, under Minnesota Rules 7849.0120 B the burden of proof is on those proposing an alternative. Considering these factors, I recommend at this time that the Commission approve the Monticello substation as the southeast termination point for the proposed Fargo, ND—Twin Cities 345 kV transmission line. That is, the facts do not clearly demonstrate the superiority of the Sherburne County substation over the

[25] All three benefits are mentioned on page 5.18 of the Petition.

Monticello substation while the Monticello substation would provide greater reliability benefits.

Q. Did you analyze any of the substations between the Fargo, ND and Monticello termination substations?

A. Yes. OES Information Request No. 10 requested information comparing the incremental impact of adding a new substation in the Alexandria area versus eliminating the substation and instead constructing 230 kV and 115 kV lines to address the Alexandria area need. The Applicants' response was that constructing a 230 kV alternative (to the Alexandria substation) would cost about $40.4 million, result in about 45 miles of transmission lines, and provide a solution through about 2025. By comparison, the incremental cost of adding a substation in the Alexandria area would cost about $12.5 million, not result in any incremental transmission (above the Applicants' proposed lines), and provide a solution through about 2050. While valuation of differential losses would be ideal, a loss valuation should favor a system with fewer miles of transmission lines and higher voltage which is the Applicants' proposal. Therefore, I conclude that the Applicants' proposal for an Alexandria-area substation is reasonable.

2) Twin Cities—La Crosse Line

Q. How did the Applicants select the southeastern termination point for the proposed Twin Cities—La Crosse, WI transmission line?

A. The last stage of the transmission study in Appendix A-2, as summarized on page 5.4 of the Petition, focused on the North La Crosse substation as the termination point (with eventual extension of the line to Columbia or West Middelton). Page 5.5 of the Petition indicates that planning engineers subsequently determined that the line should terminate at La Crosse; Figure 5-1 on page 5.6 of the Petition confirms that the line, as proposed, starts at the Hampton Corner substation and terminates at the La Crosse substation. However, page 8.5 of the Petition states that the proposed configuration starts at the Hampton Corner substation and terminates at the North La Crosse substation. I presume there is a typo, but it would be useful for the Applicants to clarify their proposed configuration in rebuttal testimony.

Q. How did you analyze the alternative system configurations for the proposed Twin Cities—La Crosse, WI transmission line?

A. OES Information Request No. 31 requested the Applicants to provide the capital costs and line losses associated with two potential termination points (La Crosse and North La Crosse). The Petition at page 8.9 states that there are three potential crossings that would terminate at the North La Crosse substation (Alma, Winona, and Trempealeau) and one crossing that would terminate at the La Crosse substation (La Crescent/La Crosse). Therefore, OES Information Request No. 31 requested comparative data regarding the La Crescent crossing and then into the La Crosse substation versus the mid-point, Winona crossing (looking at the map in Figure 8-1 on page 8.9 of the Petition) and then into the North La Crosse substation. The Applicants' response to OES Information Request No. 31 is summarized in Table 8 below.

Table 8: Twin Cities—La Crosse Configuration Data

Configuration	Cost (million $)	Losses
Winona Crossing & North La Crosse Sub	$340	Similar
La Crescent Crossing & La Crosse Sub	$330	Similar

Using the data in Table 8 and the cost values provided earlier, the cost of each configuration can be calculated. Table 8 shows that the Winona Crossing and North La Crosse substation configuration has an incremental cost of $10 million (over the La Crescent Crossing and La Crosse substation configuration). Using the cost range of between $1.19 million and $1.55 million with $1.45 for the estimated ownership structure results in the PVRR range represented in Table 9 below.[26]

Table 9: Cost of Twin Cities—La Crosse, WI Alternatives (incremental PVRR in million dollars)

Configuration	Low	Median	High
Winona Crossing & North La Crosse Sub	$ 11.90	$ 14.50	$ 15.50
La Crescent Crossing & La Crosse Sub	$ -	$ -	$ -

Table 9 demonstrates that the Applicants' proposed La Crescent crossing and La Crosse substation alternative is the least cost choice by about $12 to $16 million PVRR. Therefore, I recommend that the Commission approve the La Crosse substation and associated La Crescent crossing as the southeast termination point for the proposed Twin Cities—La Crosse, WI 345 kV transmission line. If the Applicants are aware of further information that might impact the selection of the La Crosse substation as the end-point, the Applicants should provide such information in rebuttal testimony. In particular, if either the Alma or Trempealeau crossings would have substantially different costs,

[26] I note that I assume the PVRR for the O&M costs would have a minimal impact on the choices due to the small O&M cost and small difference in miles of new corridor.

losses, routing mitigation, or socioeconomic impact information from that for the Winona crossing requested in OES Information Request No. 31, that data would be of value.

Q. Did you review the Applicants' selection of the northwestern termination point for the proposed Twin Cities—La Crosse, WI transmission line?

A. Yes. The Twin Cities—La Crosse, WI line is proposed to terminate at the Hampton Corner substation. In early engineering studies it was assumed to terminate at the Prairie Island substation. Thus, there are two potential termination points. Note that footnote 3 on page 5.7 of the Petition indicates that a third termination was considered; the alternative was discarded as it had more miles of transmission and had a higher incremental cost of $20 million.

OES Information Request No. 38 asked about the reliability impacts of the potential Hampton Corner and Prairie Island substations. The Applicants' response to OES Information Request No. 38 explains that geographic diversity in transmission lines is a consideration. In this case, having both the Prairie Island—Byron 345 kV line and the proposed Twin Cities—La Crosse, WI line start at the same substation would not necessarily involve loss of both lines being considered an N-1 situation. However, routing them significantly apart, as is part of the Applicants proposal, would provide geographic dispersion and thus reduce the probability that both lines would be lost at the same time. Thus, such a configuration would improve overall reliability.

Furthermore, the Applicants provided cost data for the two potential configurations on page 5.7 of the Petition. The Petition estimates the cost of the preferred (Hampton Corner) configuration at $330 million to $360 million and the cost of the alternative (Prairie Island) configuration at $310 million to $340 million. Thus the incremental cost of the preferred configuration is $20 million. Using the cost range of between $1.19 million and $1.55 million with $1.45 for the estimated ownership structure results in the PVRR range represented in Table 10 below.[27]

Table 10: Cost of Twin Cities—La Crosse, WI Alternatives (incremental PVRR in million dollars)

Origination	Low		Median		High	
Hampton Corner	$	23.80	$	29.00	$	31.00
Prairie Island	$	-	$	-	$	-

Table 10 demonstrates that the Prairie Island substation alternative is the least cost choice by $24 to $31 million PVRR. In this instance the Applicants have proposed the Hampton Corner substation termination. Considering the trade off between reliability and cost discussed above, I recommend that the Commission approve the Hampton Corner substation as the northwest termination point for the proposed Twin Cities—La Crosse, WI 345 kV transmission line. That is, the facts do not clearly demonstrate the superiority of the Prairie Island substation over the Hampton Corner substation.

3) Brookings, SD-Twin Cities Line

Q. How did the Applicants select the proposed configuration for the Brookings, SD—Twin Cities transmission line?

A. The Petition explains at page 5.24 that the proposed configuration was determined to be the best performing option by the EHV study provided in Appendix A-4 of the Petition. The Petition states the proposed configuration was selected as having the best results with respect to:

[27] Page 133 of Appendix A-2 of the Petition indicates that choice of the Hampton Corners substation would result in an additional 5 miles of transmission. If all 5 miles were new corridor, the PVRR for the incremental O&M costs would be minimal, less than $60,000.

- steady state and dynamic power system performance;
- prevention of inadvertent power flows;
- power transfer capability;
- power and energy losses;
- practicality; and
- price.

Q. How did you analyze the alternative system configurations for the proposed Brookings, SD—Twin Cities transmission line?

A. OES Information Request No. 32 requested the Applicants to provide the capital costs and line losses associated with two potential configurations. The potential configurations are the Applicants' proposed configuration and the West Waconia alternative. The West Waconia alternative consists of two lines:

- a 345 kV Brookings County—Lyon County—Hazel Creek—West Waconia—Helena—Lake Marion—Hampton Corner line; and
- a 230 kV Hazel Creek—Minnesota Valley line.

The Applicants' response to OES Information Request No. 32 is summarized in Table 11 below.

Table 11: Brookings, SD—Twin Cities Configuration Data

Configuration	Cost (million $)	Losses On-Peak	Losses Off-Peak
Applicants Proposal	$600 to $665	-	-
West Waconia	$615	91 MW	101 MW

Using the data in Table 11 and the cost values provided earlier, the cost of each configuration can be calculated. Table 11 shows that the Applicants' proposal has a cost range of $600 to $665 million, for a mid-point cost of $632.5 million. Considering the mid-point of the range, the Applicants' proposal has an incremental cost of $632.5 million minus $615 million or $17.5 million (over the West Waconia configuration). Using the cost range of between $1.19 million and $1.55 million with $1.45 for the mid-point results in the PVRR range represented in Table 12 below.

Table 12: Capital Cost of Brookings, SD—Twin Cities Alternatives (incremental PVRR in million dollars)

Configuration	Low	Median	High
Applicants Proposal	$ -	$ -	$ -
West Waconia	$ 20.83	$ 25.38	$ 27.13

Table 11 also shows that the Applicants' proposal has lower losses, by 91 MW on-peak and 101 MW off-peak. Using the values in Table 5 above results in the PVRR range represented in Table 13 below for energy costs.

Table 13: Present Value of Incremental Energy Cost of the West Waconia Alternative (incremental PVRR in million dollars)

Cost Level	Public Power	Investor Owned	Project Average
Low Energy Cost	$ 459.55	$ 342.16	$ 370.37
High Energy Cost	$ 625.17	$ 465.92	$ 504.14

Using the values for demand costs discussed above results in the PVRR range represented in Table 14 below for demand costs.

Table 14: Present Value of Incremental Demand Cost of the West Waconia Alternative (incremental PVRR in million dollars)

Configuration	Public Power	Investor Owned	Weighted Average
Applicants Proposal	$ -	$ -	$ -
West Waconia	$ 111.93	$ 142.87	$ 134.68

The data in Tables 12, 13, and 14 clearly demonstrate that the Applicants' proposal is the least cost alternative.[28] I recommend that the Commission approve the

[28] Any O&M cost differential would be minimal in comparison to the loss cost differential.

Applicants' proposed configuration for the Brookings, SD—Twin Cities 345 kV transmission line.

Q. Are the facilities proposed in the Big Stone 2 proceeding, which is docket number E017 et al/CN-05-619, necessary for the proposed configuration of the Brookings, SD—Twin Cities line to perform adequately?

A. No. The proposed Big Stone 2 facilities are not necessary for the proposed configuration to perform adequately. OES Information Request No. 23 asked that precise question "Are any of the Big Stone II generation and associated interconnection facility additions necessary for the transmission lines proposed in this proceeding to perform adequately?" The Applicants' response, in part, was "The transmission lines in this proceeding will perform adequately regardless of whether or not any of the Big Stone II generation and associated interconnection facility additions are constructed."

The issue is not that the Big Stone II lines have no function. Rather there are a number of ways to fulfill that function. Specifically, the response to OES Information Request No. 23 states:

> Additional transmission lines are needed around Buffalo Ridge to connect generators to the bulk power system, add transmission capacity, and address local system deficiencies. The Big Stone II interconnection facilities help achieve those functions. Without the Big Stone II interconnection facilities, an alternative local transmission configuration would need to be designed for the Buffalo Ridge area.
>
> If one assumes the Big Stone II interconnection facility additions are not constructed, either the assumed incremental generation injection points for the Twin Cities -Brookings County 345 kV line would have to change, or additional transmission lines would need to be installed in

> the northern part of the Buffalo Ridge to restore outlet capability…

In summary, if the Big Stone II transmission facilities are not constructed, either the generators will need to be moved towards the proposed facilities or additional transmission would need to be constructed to move the termination point of proposed facilities towards the generators.

4) Summary of Configuration Analysis

Q. Please summarize your analysis of the proposed configuration.

A. Based upon the above analysis, I conclude that the Applicants have shown the reasonableness of the following proposed configuration and recommend that the Commission approve:

- the Applicants' proposed configuration for the proposed Fargo, ND—Twin Cities line;
- the Applicants' proposed configuration for the Brookings, SD—Twin Cities line;
- the La Crosse substation and associated La Crescent crossing as the southeast termination point for the proposed Twin Cities—La Crosse, WI line; and
- for the remainder of the proposed Twin Cities—La Crosse, WI line, approve the Applicants' proposed configuration.

b. Cost Analysis of Alternatives

Q. What is the cost of the Applicants' proposal?

A. The cost of the Applicants proposal is calculated in OES Exhibit No. ___ (SRR-13); the total cost varies between $0.88 billion (low costs, all public power ownership), and $1.77 billion (high costs, all investor owned). The cost using the Applicants' estimated ownership structure is between $1.30 billion (low costs) and $1.58 billion (high costs).

Q. What alternatives to the Applicants' proposal did you analyze in detail?

A. I analyzed an alternative that proposed building the proposed Fargo, ND—Twin Cities and Brookings, SD—Twin Cities lines but sizing the lines to 500 kV, and operating the lines initially at either 345 kV or 500 kV. I also reviewed the Applicants' analysis of a 161 kV alternative to the proposed Twin Cities—La Crosse, WI line.

Q. Please explain the lower voltage analysis process.

A. I reviewed the Applicants' analysis and requested further information clarifying the line losses. Based upon my review of this data, I conclude that the 161 kV alternative has higher capital costs and higher losses than the 345 kV proposal. Further discussion is provided below.

Q. Please explain the higher voltage analysis process.

A. OES Information Request No. 40 requested the Applicants to provide cost and loss data for two proposed options: a 500 kV build/345 kV operation and a 500 kV build/500 kV operation option for the proposed Fargo, ND-Twin Cities and Brookings, SD-Twin Cities lines.

Using the loss and capital cost data provided by the Applicants' response to OES Information Request No. 40 and my economic analysis discussed above, I calculated the cost of switching the Applicants' 345 kV proposal to 500 kV operation. Since I assume that the miles of new transmission would be similar for either 345 kV or 500 kV based upon construction, I did not consider O&M costs as the Petition at page 9.17 indicated that O&M costs are roughly the same for voltages 115kV through 345 kV. I performed these calculations for both the proposed Fargo, ND—Twin Cities line and the proposed Brookings, SD—Twin Cities line.

Q. Did you consider any non-cost information in your determination to do an analysis of a 500 kV alternative?

A. Yes, I did. From a policy perspective, one of the most interesting and informative parts of the Petition is section 3.4. Section 3.4.2 explains that, during the 1950s 115 kV was the standard size transmission line and was adequate at the time. Thus, when planning the metro ring, Minnesota planners looked at continuing with 115 kV and introducing 230 kV. However, in the end Minnesota planners decided to go a step beyond the standard of the day, to implement 345 kV transmission for the metro ring. The Petition concludes that going a step beyond the standard of the day resulted in a system that remains basically reliable today. Footnote 14 of the Petition compares the Minnesota experience to that of Denver, Colorado, where planners in the 1960s did not 'go a step beyond' and significant investment is now necessary because the 230 kV Denver metro ring has reached capacity.

This comparison and its consequences can be applied to the issue at hand. By way of comparison, for our planning today, going a step beyond the standard would mean considering 500 kV rather than the now standard 345 kV. Given the long term nature of transmission investment, consideration of the long-term benefits of going beyond the current standard is reasonable.

1) Fargo, ND—Twin Cities at 500 kV

Q. Please provide your cost assessment for the 500 kV alternative for the Fargo, ND—Twin Cities line.

A. First, the Applicants' response to OES Information Request No. 40 stated that constructing the Fargo, ND—Twin Cities line to 500 kV but operating at 345 kV "is not a reasonable option because it would not provide additional load serving capability or improve overall system performance." After reviewing the data I agreed with the Applicants that building the Fargo, ND—Twin Cities line to 500 kV but operating at 345 kV until further events occur before switching to 500 kV operation was not economically justified. Therefore, my analysis focused upon the "build and operate at 500 kV" alternative.

Second, for the capital cost, the Applicants' response to OES Information Request No. 40 indicates that the incremental capital cost of building to 500 kV rather than 345 kV would be $133 million. I assumed that, consistent with the other Applicant investment cost data that the $133 million is in 2007 dollars. Therefore, I inflated that cost by 2.5 percent to obtain $136.33 million in 2008 dollars. Then, I multiplied $136.33 million of investment cost by the factor representing the present value of the annual revenue requirements per million dollars of investment cost from OES Exhibit No. ___ (SRR-7) to obtain the overall present value of the investment costs. The results are shown in OES Exhibit No. ___ (SRR-14).

Third, for the demand loss benefits, the Applicants' response to OES Information Request No. 40 provides a variety of MW loss figures. I used the on-peak losses associated with building and operating the lines at 500 kV for both the zero additional-transfers (0 MW Transfer columns) and the increased-transfer columns (the columns labeled 1,250 MW or 1,000 MW Transfer). I did so for a future with and without a Winnipeg -- Fargo, ND line. This line is currently under study so it is included here as it appears relevant to the analysis of the proposed Fargo, ND -- Twin Cities line. These loss figures were multiplied by the present value of the annual revenue requirements per MW of demand losses factor from OES Exhibit No. ___ (SRR-9) to obtain the overall present value of the capacity benefit associated with the avoided demand losses. The results are shown in OES Exhibit No. ___ (SRR-14).

For the energy losses, as explained previously, to be consistent with the energy loss method of the underlying transmission study (provided in Appendix A-3 of the Petition) I used the on-peak losses associated with building and operating at 500 kV for both the zero additional transfers and the increased transfer cases. These MW loss figures were multiplied by the present value of the annual revenue requirements for the energy cost associated with each MW of demand losses from OES Exhibit No. ___ (SRR-11) at both the low energy loss value and the high energy loss value to obtain the overall present value of the energy benefit associated with the avoided demand losses. The results are shown in OES Exhibit No. ___ (SRR-14).

Finally, I summed the present value of the capital costs, the avoided demand loss benefit, and the avoided energy loss benefit. The results are summarized below in Table 15 and details of the calculations are available in OES Exhibit No. ___ (SRR-14).

Table 15: Summary of Incremental PVRR Benefit of 500 kV Operation
(PVRR million dollars assuming estimated ownership structure)

	With Winnipeg-Fargo 500 kV	Without Winnipeg-Fargo 500 kV
No Added Transfer	\$2 - \$55	(\$87) - (\$57)
Increased Transfer	\$301 - \$434	\$245 - \$152

Table 15 demonstrates that under three of the four potential scenarios building at 500 kV would represent an overall cost savings at the estimated ownership structure. Only if no new transmission from Winnipeg is built and no additional transfers occur is the Applicants' proposal of a 345 kV line the least cost choice. In other words, anything that would increase use of the proposed line above the level assumed by the Applicants makes the 500 kV alternative least cost.

Q. Can you reduce the values in Table 15 to a single number?

A. Yes I can. I do not know of a method to determine with certainty the probability of any one of the four scenarios occurring. However, if each of the four potential outcomes is assumed to be equally probable, the expected value of the PVRR benefit of building at 500 kV versus 345 kV, using the low values, is \$92.07 million and is \$169.11 million using the high values. See OES Exhibit No. ___ (SRR-14) for details. In other words, the expected incremental benefit of the 500 kV alternative is positive (i.e. more cost effective than the 345 kV proposal) under either the low values or the high values.

As a contingency, I raised the probability of the Applicants' base case occurring to 50 percent and reduced the other scenarios as follows:

- Without transmission but 1,250 MW transfer to 20 percent;
- With new transmission but 0 MW transfer to 20 percent; and
- With new transmission and 1,250 MW transfer to 10 percent.

The expected value of the 500 kV alternative remained positive (a net benefit) with a range of $17.48 million to $74.69 million. I further altered the probabilities (in the same order) to 60/15/15/10 and obtained an expected value of $1.12 million to $53.98 million (a benefit) for the 500 kW scenario over the 345 kV proposal. In other words, the net benefits of building the 500 kV is eliminated only if it is known with a fairly high degree of certainty that no new transmission from Winnipeg will be built and no additional transfers will occur.

Q. Your calculations of avoided costs are based upon an on-peak line loss savings of up to 90 MW. Can you illustrate how big 90 MW of avoided losses are?

A. The November 29, 2006 *Decision* of the Deputy Commissioner of the Minnesota Department of Commerce (Docket No. E,G002/CIP-06-80) approved demand savings goals for Xcel's entire conservation improvement program (CIP). The Deputy Commissioner's approved demand savings goals are 87.3 MW in 2007, 91.0 MW in 2008, and 92.8 in 2009. Thus, the potential 90 MW of incremental, annual demand savings attributable to the 500 kV alternative are approximately equal to the annual demand savings goal of Xcel's entire CIP. Finally, I note that the incremental transmission costs ($133 million) are higher than the costs of Xcel's CIP (about $50 million), but a transmission line has a much longer useful life than a typical CIP measure.

The 500 kV alternative could also have annual energy savings somewhat greater than Xcel's entire CIP. Using the 41.5 percent load factor from the Applicants' transmission study (see Appendix A-3 of the Petition) and 8,760 hours per year, 90 MW of avoided, incremental demand losses translates into 327,186 MWh of annual energy savings.[29] This amount can be compared to the Deputy Commissioner-approved annual energy savings goals for Xcel's CIP of 238,213 MWh in 2007, 259,635 MW in 2008, and 264,114 in 2009. Thus, the incremental, annual energy savings attributable to the 500 kV alternative are 24 percent greater than the highest annual energy savings goal approved for Xcel's entire CIP during the 2007-2009 period. Again, the incremental transmission costs are higher than the costs of Xcel's CIP, but a transmission line has a much longer useful life than a typical CIP measure.

Q. What do these comparisons mean?

A. These comparisons mean that the alternative of building the Fargo—Twin Cities line at 500 kV rather than 345 kV would result in demand and energy savings that are larger than any energy conservation measure in the history of the state. That holds regardless of which of the four potential futures actually occurs.

[29] For completeness I note that the equivalent energy savings for the other scenarios are:

- 20 MW demand loss = 72,708 MWh per year;
- 36 MW demand loss = 130,874 MWh per year; and
- 63 MW demand loss = 229,030 MWh per year.

The alternative of building the Fargo—Twin Cities line at 500 kV would result in demand and energy savings that are as large as or larger than any energy conservation program (as currently approved by the Deputy Commissioner of the Department of Commerce) under the 90 MW demand savings future.

Q. Can you calculate the CO_2 equivalent of the 500 kV alternative?

A. Yes, I can. Using the emissions rate for Xcel[30] as a proxy for the system as a whole, 327,186 annual avoided MWh translates into 252,240 tons of avoided CO_2 annually.[31]

Q. Did you perform any other sensitivity tests?

A. Yes I did. The response to OES Information Request No. 40 stated that "results of the 500 kV construction/500 kV operation scenario analysis identified approximately four additional underlying system overloads that would require mitigation in order to achieve the same transfer levels attained by the 345 kV proposal." Therefore, as a contingency I assumed (since no cost figures were provided) an incremental capital cost of $190 million in 2007 dollars and then inflated that figure to $194.75 million in 2008 dollars using the standard 2.5 percent inflation rate used in this testimony. A $194.75 million incremental cost represents an increase of about $58.42 million over the incremental cost specified by the Applicants for 500 kV construction and operation, when translated into equivalent, 2008 dollars. This increase is intended to reflect the costs of fixing the underlying problems. Note that this estimate was created assuming approximately a 40 percent

[30] See Table 3 of this testimony.
[31] The avoided CO_2 emissions at the other levels are:
- 20 MW demand loss = 56,053 tons CO_2;
- 36 MW demand loss = 100,896 tons CO_2; and
- 63 MW demand loss = 176,568 tons CO_2.

increase in the capital costs to account for the fixes to the underlying system. It would be helpful for the Applicants to provide a more reasonable estimate of this cost in rebuttal testimony. Using the same calculation process as before and assigning an equal probability to the four potential outcomes results in an expected value (the PVRR benefit) of building and operating at 500 kV of $7.35 million using the low values and $84.39 million using the high values. See OES Exhibit No. ___ (SRR-15) for the calculations.

Q. Can you summarize your analysis of the 500 kV alternative to the Fargo, ND—Twin Cities line?

A. In summary, I conclude, based on the information available in the response to OES Information Request No. 40, that building and operating the Fargo, ND—Twin Cities line at 500 kV is the least cost choice. Therefore, I recommend that the Commission modify the Applicants' proposal and approve a CN for a 500 kV size of the Fargo, ND—Twin Cities line. I also invite the Applicants to provided further information pertinent to a 500 kW build/operate alternative.

Q. The Applicants' response to OES Information Request No. 40 contains information on an alternative with a 500 kV line and a 345 kV line. What is your analysis of this information?

A. The Applicants' response to OES Information Request No. 40 provided loss data for an alternative with a 500 kV line and a 345 kV line. The Applicants' response did not provide an estimated capital cost, nor clarify if the alternative is intended to be a double circuit 500 kV/345 kV line or if two separate lines were intended; I should clarify that my request did not ask for such data. For purposes of the discussion, I will refer to the 500 kV/345 kV alternative.

With the loss data but without an incremental capital cost I can work backwards and determine the incremental capital budget that would allow the 500 kV/345 kV alternative to be equal to or lower in cost than the Applicants proposal. The calculations are similar to those outlined above. The details of the calculations for the 500 kV/345 kV alternative can be found in OES Exhibit No. ___ (SRR-16). The result is that, using the low values, an incremental capital cost (in 2008 dollars) of less than or equal to $253.35 million would leave the 500 kV/345 kV alternative as equal or lower in cost than the Applicants' proposal. Using the high values, an incremental capital cost (in 2008 dollars) of less than or equal to $522.81 million would leave the 500 kV/345 kV alternative as equal or lower in cost than the Applicants' proposal.

In summary, the range of the break-even point for the incremental capital cost of the 500 kV/345 kV alternative relative to the Applicants' proposal is between $253.35 million to $522.81 million. Assuming that a separate corridor is necessary for the 500 kV line away from the 345 kV line, this range can be compared to the ($136.33 plus $399.75) $536.08 minimum cost for an additional, separate 500 KV line. Therefore, I conclude that two separate lines, 500 kV and 345 kV, cannot be the least cost alternative. However, it appears that a double circuit 500kV/345 kV line may be justifiable economically, if it could meet engineering-reliability criteria.

Note that this discussion does not consider the greater system-wide growth related benefits of the 500 kV/345 kV alternative. Rather, it assumes the same level of such benefits as that proposed by the Applicants. It may be the case that two separate lines

(500 kV and 345 kV) would provide greater generation interconnection and transfer/delivery capability at a lower cost per MW (or per MWh). However, greater connection and transfer/delivery than the Applicants' proposal is not the issue at hand.

2) Brookings, SD—Twin Cities at 500 kV

Q. Please provide your cost assessment for the 500 kV alternative for the Brookings, SD—Twin Cities line.

A. First, as noted above, after reviewing the data I agreed with the Applicants that building the Brookings, SD—Twin Cities line to 500 kV but operating at 345 kV until further events occur to switch to 500 kV operation was not economically justified. Therefore, my analysis again focused upon the alternative of building and operating the line at 500 kV. Using the same calculation process as before, I used the low estimate of the incremental capital cost and the incremental line losses associated with a 500 kV alternative and estimated the net present value of the annual revenue requirements for the increment in the four scenarios provided by the Applicants. The results are summarized below in Table 16 and details of the calculations are available in OES Exhibit No. ___ (SRR-17).

Table 16: Summary of Incremental PVRR of 500 kV Operation
(PVRR million dollars)

	With MN Valley-Blue Lake Rebuild	**Without MN Valley-Blue Lake Rebuild**
1,200 MW Transfer	($219)-($218)	($226)-($223)
2,400 MW Transfer	($118)-($92)	($134)-($113)

Q. Do you have any other comments on the Brookings, SD—Twin Cities 500 kV alternative?

A. Yes, the Applicants' response to Joint Intervener Information Request No. 18 states that:

- a double circuit bundled 345 kV, 954 ACSS line would cost about $1,880,000 per mile; and
- Single circuit tri-bundled 500 kV, 1192 ACSR (design of the Dorsey-Forbes-Chisago County 500 kV line) would cost about $1,611,000 per mile.[32]

That is, this response indicates that the double circuit 345 kV line has a higher per mile cost than a single circuit 500 kV line. However, the Applicants' response to OES Information Request No. 40 states that "The estimated total cost increase to substations and transmission lines for a similarly performing 500 kV design is $176,200,000 to 184,900,000." That is, the response to the OES's request indicates that a single circuit 500 kV line has a much greater total cost than a double circuit 345 kV line. While it is clear that the responses are covering different sets of costs, it is not clear what is driving the significantly different results in terms of cost rankings in the two responses. Therefore, I recommend that, in rebuttal testimony, the Applicants' explain the different cost ranking results provided in the responses to OES Information Request No. 40 and Joint Intervener Information Request No. 18.

Q. What is your conclusion regarding this analysis?

A. As indicated in Table 16, the alternative of building and operating the Brooking, SD—Twin Cities line at 500 kV would be more costly under all four scenarios. Considering the poor economic performance of the 500 kV alternative for the Brookings, SD—Twin Cities line under all scenarios, I did not pursue the issue further.

[32] Note that "permitting, right-of way acquisition, and project and construction management are not included in these costs."

3) Summary of 500 kV Analysis

Q. Can you summarize your recommendations of 500 kV alternatives?

A. I recommend that the Commission approve a 500 kV size modification to the Fargo, ND—Twin Cities line. The 500 kV alternative to the Brookings, SD—Twin Cities 345 kV proposal should not be given further consideration.

4) Twin Cities—La Crosse, WI at 161 kV

Q. Please explain your analysis of the Applicants' 161 kV alternative to the proposed Twin Cities—La Crosse, WI 345 kV line.

A. I generally followed the same calculation process as with the analysis of the 500 kV alternatives provided above. However, in the 500 kV cases there were no differential timing issues since the projects were assumed to be constructed on the same time line. That is not the case with the 161 kV alternative to the proposed Twin Cities—La Crosse, WI 345 kV line, which is assumed to be constructed in stages. Therefore, I had to slightly change the calculations to account for the different timing impacts. Since loss data was not provided in the Petition, I used the loss data provided by the Applicants in response to OES Information Request No. 44. However, to avoid further complications regarding creating updated investment costs for the 161 kV alternative, I simply used the investment costs provided in Appendix A-2 of the Petition, at pages 159 to 161 for both the 161 kV and 345 kV alternatives. The results of the calculations are summarized below in Table 17 for the low energy values and details of the calculations are available in OES Exhibit No. ___ (SRR-18).

Table 17: Summary of 161 kV versus 345 kV
(PVRR million dollars)

	161 kV	345 kV
Capital Cost	$256.18	$221.53
Loss Cost	$ -	$ (19.41)
Total	$256.18	$202.12

Q. What is your conclusion based upon this analysis?

A. My conclusion is similar to that of the Applicants in Appendix A-2 of the Petition; Table 17 demonstrates that the 345 kV alternative has both a lower capital cost and a better loss performance than the 161 kV alternative. Therefore, I recommend that the Commission approve the Applicants' proposed CN for the Twin Cities—La Crosse, WI 345 kV line.

V. ANALYSIS OF POLICY

A. POLICIES, RULES, AND REGULATIONS

Q. What is the rule criterion regarding permits required by local, state, or federal governmental agencies?

A. Minnesota Rules 7849.0120 D requires a determination that "the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification to the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments."

Q. Have you reviewed the Applicants' list of permits that may be required by local, state, or federal governmental agencies?

A. Yes. I reviewed the list of related filings and permits on pages 8.37 and 8.38 of the Petition.

Q. Have you investigated whether those permits will be granted?

A. No.

Q. Do you know of any reason why those permits would not be granted?

A. No. I presume that the various agencies with jurisdiction over the permits will review and confirm that the Applicants are in compliance prior to granting their permits. In general I rely on the agencies to enforce their requirements.

B. PROMOTIONAL PRACTICES

Q. What is the rule criterion regarding the effects of promotional practices of the Applicants?

A. Minnesota Rules 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.

Q. How did you assess the promotional practices of the Applicants?

A. The OES has reviewed the promotional practices of both Xcel and GRE multiple times between 2006 and the present:

- for Xcel see Docket Nos. E002/CN-04-1176, E002/CN-06-154, and E002/CN-07-873; and
- for GRE see Docket Nos. E017 et al/CN-05-619 and ET2/CN-07-678, and ET2/CN-06-363.

Also, a detailed review of many other utilities was carried out recently in the Big Stone 2 proceeding (See Docket No. E017 et al/CN-05-619). Therefore, I did not seek new information on this topic. Further, as explained elsewhere in this testimony and that of other OES witnesses, the need for these facilities is, in part, driven by compliance with the renewable energy standard of Minnesota Statutes. While promotional practices could increase the amount of renewable energy to be added as a result of the RES, such effects would be minor compared to the effect that passage of the RES has had on the need for new transmission lines.

In summary, I conclude that that this rule criterion has been met.

C. TRANSMISSION PLANNING COMPLIANCE

Q. Please explain your review of the Applicants' compliance with Minnesota Statutes §216B.243, subd. 3 (10).

A. Minnesota Statutes §216B.243, subd. 3 (10) states that the Commission shall evaluate:

> whether the applicant or applicants are in compliance with applicable provisions of … 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.

In turn, Minnesota Statutes §216B.2425, subd. 7 states:

> (a) Each entity subject to this section shall determine necessary transmission upgrades to support development of renewable energy resources required to meet objectives under section 216B.1691 and shall include those upgrades in its report under subdivision 2.[33]
> (b) Transmission projects determined by the Commission to be necessary to support a utility's plan under section

[33] Note that subdivision 2 establishes the biennial transmission plan.

> 216B.1691 to meet its obligations under that section must be certified as a priority electric transmission project, satisfying the requirements of section 216B.243. In determining that a proposed transmission project is necessary to support a utility's plan under section 216B.1691, the Commission must find that the applicant has met the following factors:
> (1) that the transmission facility is necessary to allow the delivery of power from renewable sources of energy to retail customers in Minnesota;
> (2) that the applicant has signed or will sign power purchase agreements, subject to commission approval, for resources to meet the renewable energy objective that are dependent upon or will use the capacity of the transmission facility to serve retail customers in Minnesota;
> (3) that the installation and commercial operation date of the renewable resources to satisfy the renewable energy objective will match the planned in-service date of the transmission facility; and
> (4) that the proposed transmission facility is consistent with a least-cost solution to the utility's need for additional electricity.

I note that subdivision 7, paragraph (b), as added by Laws 2005, chapter 97, article 2, section 3, expires January 1, 2010. In the most recent biennial transmission plan (Docket No. E999/M-07-1028) the utilities identified and discussed transmission to meet the renewable energy objectives. The items pertinent to this discussion are (by utility with a quote):

- Dairyland Power Cooperative—"As far as additional transmission infrastructure required to ensure compliance with the RES milestones, the items identified in this Report in the Southwest Zone will help ensure compliance."
- Interstate Power and Light Company d/b/a Alliant Energy Currently (IP&L)—"IP&L has approximately 1,000 MW worth of new wind generation intending to connect to the IP&L control area in Minnesota and Iowa as part of the

MISO's Group 5 Study, and the MISO has recently released its study results. The Study provides evaluation of the impact of this new generation and identifies needed system upgrades. A significant number of transmission upgrades to the IP&L transmission system will be required to enable the interconnection of the generation. The upgrades are extensive and will require several years to complete the upgrades; these upgrades will assist in providing the infrastructure necessary to comply with the renewable energy mandate."

- Xcel—"Xcel is actively working with the members of the Minnesota Transmission Owners' group to define the transmission necessary for each utility to meet its RES milestones. It is anticipated that the 2012 and all future milestones will be met through this collaboration. For more details on the work being performed jointly by the utilities in the state, please see the RES Report included as Part II of this document."
- Otter Tail Power Company (OTP)—"OTP is expecting that large-scale transmission improvements will be needed as more renewable energy is added to the transmission system, including those identified through the CapX planning efforts."
- Rochester Public Utilities—"Rochester Public Utilities is actively pursuing investigations into how it may expand its existing renewable programs to gather additional benefits from renewable energy and is participating with the other Minnesota utilities in the studies and other efforts required to achieve the RES milestones."

Furthermore, as discussed above, the RES Report lists several transmission lines as necessary to support achievement of the renewable energy standard. In chapter five the RES Report states "The law requiring the utilities to file this Renewable Energy Standards Report requires the utilities to report on specific transmission line proposals that are necessary to meet intermediate RES milestones." The RES Report then proceeds to list:

- Southwest Minnesota 345 kV Project—approved in Docket No. E002/CN-01-1958);
- Buffalo Ridge Incremental Generator Outlet (BRIGO)—approved in Docket No. E002/CN-06-154;
- Storden to Dotson Project—the utilities "will begin a study in early 2008;"
- Fargo, ND to Twin Cities 345 kV Project—proposed in this docket;
- Brookings, SD to Twin Cities 345 kV Project—proposed in this docket;
- Bemidji to Grand Rapids 230 kV Project—proposed in Docket No. E015 et al/CN-07-1222; and
- Big Stone Transmission—proposed in Docket No. E017 et al/CN-05-619.

Therefore, I conclude that this statutory criterion has been met.

D. ENVIRONMENTAL COST PLANNING

Q. Please explain your review of the Applicants' compliance with Minnesota Statutes §216B.243, subd. 3. (12).

A. Minnesota Statutes §216B.243, subd. 3. (12) states that the Commission shall evaluate:

> … if the applicant is proposing a <u>nonrenewable generating plant</u>, 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 that risk. (Emphasis added)

In this docket the Applicants are proposing transmission lines rather than a nonrenewable generating plant. Therefore, this statutory criterion does not appear to apply.

E. INNOVATIVE ENERGY PROJECT PREFERENCE

Q. Please explain your review of the Applicants' compliance with Minnesota Statutes §216B.1694, subd. 2 (a) (5).

A. Minnesota Statutes §216B.1694, subd. 2 (a) (5) states that an innovative energy project:

> … shall, prior to the approval by the commission of any arrangement to build or expand a <u>fossil-fuel-fired generation facility</u>, or to enter into an agreement to purchase capacity or energy from such a facility for a term exceeding five years, be considered as a supply option for the generation facility, and the commission shall ensure such consideration and take any action with respect to such supply proposal that it deems to be in the best interest of ratepayers; (Emphasis added)

In this docket the Applicants are proposing transmission lines rather than a fossil-fuel-fired generation facility. Therefore, this statutory criterion does not appear to apply.

VI. SUMMARY AND RECOMMENDATIONS

Q. Please summarize your recommendations regarding the Petition.

A. Based upon the information provided to date, I recommend that the Commission determine that the Petition as modified to reflect 500 kV size for the Fargo, ND—Twin Cities line meets the criterion of the following Minnesota Rules:

- 7849.0120 A (3);

- 7849.0120 A (4);
- 7849.0120 B (1);
- 7849.0120 B (2);
- 7849.0120 B (3); and
- 7849.0120 D.

I also recommend that the Commission determine that the Petition as modified to reflect 500 kV size for the Fargo, ND—Twin Cities line meets the criterion established by the following Minnesota Statutes:

- 216B.1694, subd. 2;
- 216B.2422, subd. 4;
- 216B.2426;
- 216B.243, subd. 3. (10);
- 216B.243, subd. 3. (12); and
- 216B.243, subd. 3a.

Q. What is your overall recommendation regarding the CNs requested by the Petition?

A. Based on the information provided to date, I recommend that the Commission approve CNs as proposed or modified for the following facilities:

- a 345 kV transmission line between a new Hampton Corner substation in the southeast corner of the Twin Cities and the La Crosse substation, crossing the Wisconsin-Minnesota border near La Crescent as indicated in the maps included in the CN notice materials;

- a 500 kV transmission line between the Monticello substation and the Maple River substation, crossing the North Dakota-Minnesota border as indicated in the maps included in the CN notice materials;
- a 345 kV transmission line between a new Hampton Corner substation in the southeast corner of the Twin Cities and the Brookings County substation, crossing the South Dakota-Minnesota border as indicated in the maps included in the CN notice materials;
- a 345 kV transmission line from the Lyon County substation to the new Hazel Creek substation in the Granite Falls area;
- a 161 kV transmission line from the North Rochester substation to the Northern Hills substation; and
- a 161 kV transmission line from the North Rochester substation to the Chester substation.

Furthermore, I recommend that in rebuttal testimony the Applicants provide:

- an explanation for why generation was not considered as an alternative to the Fargo, ND—Twin Cities project;
- an estimate of the cost to mitigate additional underlying system problems for the 500 kV alternative;
- a response to my "up-sizing" to 500 kV modification of the transmission line from the Monticello substation to the Maple River substation;
- an update regarding the CN requested for the voltage and number of circuits for the proposed 230 kV Hazel Creek substation to Minnesota Valley substation segment;

- a clarification of the proposed termination point (La Crosse or North La Crosse substations) for the proposed Twin Cities-La Crosse, WI transmission line;
- any further information that might impact the selection of the La Crosse substation as the end-point; for example, if either the Alma or Trempealeau crossings would have substantially different cost, losses, routing mitigation or socioeconomic impact information from that for the Winona crossing requested in OES Information Request No. 31, that data would be of value;
- an explanation for the different cost ranking results provided in response to OES Information Request No. 40 and Joint Intervener Information Request No. 18; and
- an explanation if there is a more appropriate measure of added generation export capability created by the proposed transmission facilities than the one discussed in my testimony (see above).

Q. Does the OES have an overall recommendation at this time?

A. No. The OES continues to review all information offered into the record of this case. At the time that most of the information has been entered by parties, OES will present its overall recommendation based on its review of the record at that time.

Q. Does this conclude your direct testimony or do you have something more to say?

A. I'm done, for now.