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

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

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 EXHIBITS OF DR. STEVE RAKOW

ON BEHALF

OF THE MINNESOTA OFFICE OF ENERGY SECURITY

MAY 23, 2008

PUBLIC COPY
TRADE SECRET DATA EXTRACTED

Steve Rakow
Minnesota Office of Energy Security
85 7th Place East, Suite 500
St. Paul, MN 55101-2145

Professional Background

1996 to present Public Utilities Rates Analyst • Minnesota Office of Energy Security. Analyze resource plans, certificates of need, and miscellaneous public policy issues. Testify before the Minnesota Public Utilities Commission in contested-case proceedings. A list of related filings analyzed and testimony presented is included below.

1999 to 2005 Board of Governors • MinforMed, L.L.C. Wrote portions of and advised on the economic and business sections of several grant proposals and the 2002 business plan. Named to Board of Directors, March, 2000.

1995 Instructor • University of Nebraska-Omaha. Taught Principles of Macroeconomics.

1993 to 1994 Instructor and Academic Assistant to the Rector • Concordia International University-Estonia. Taught Introduction to Economics. Wrote Student Handbook and Faculty Introduction to Tallinn Handbook.

1993 Instructor • Concordia University-Nebraska. Taught Principles of Microeconomics.

1989 to 1993 Graduate Teaching Assistant • University of Nebraska. Taught Introduction to Economics, Principles of Microeconomics, Principles of Macroeconomics, Current Economic Issues and Intermediate Macroeconomics. Specialized in public policy, economic history and comparative economics.

Education

Doctor of Philosophy, Economics, University of Nebraska, December 1994

Master of Arts, Economics, Mankato State University, March 1989

Bachelor of Arts, Economics, Moorhead State University, May 1987

Bachelor of Science, Accounting, Moorhead State University, May 1987

Testimony and Comments in Certificate of Need Proceedings

Docket No.	Company	Project	Subjects
E002, ET3/ CN-04-1176	Xcel, Dairyland	Chisago-Apple R. 115/161 kV	Planning Background, Alternatives, Policy
E017 et al/ CN-05-0619	OTP et al	Big Stone-Morris 230 kV Big Stone-Granite F. 345 kV	Planning Background, Alternatives, Policy
E017/CN-06-0677	OTP	Appleton-Canby 115 kV	All Areas
E999/TL-05-1739	GRE, MP	Park Rapids-Pequot L. 115 kV	All Areas
E002/CN-05-0123	Xcel Energy	Monticello ISFSI	Alternatives, Policy
E002/CN-04-0076	Xcel Energy	Blue Lake CT	Alternatives
IP6339/CN-03-1841	Trimont LLC	Trimont Wind	Settlement-Alternatives
IP6202/CN-02-2006	MMPA	Faribault CC	Settlement-Electric, Environmental Report
ET2/CN-02-0536	GRE	Plymouth-Maple Gr. 115 kV	Forecasting
E002/CN-01-1958	Xcel Energy	SW Minn. 115/161/345 kV	Forecasting
PL9/CN-01-1092	Lakehead	Clearbrook-Superior Oil Pipeline	Alternatives, Consequences to Society
E002/CN-99-1815	NSP	Black Dog CC	Alternatives, Forecasting
ET2/CN-99-0976	GRE	Pleasant Valley CT	Consequences to Society, Forecasting, Environmental Report
IP3/CN-98-1453	Tenaska NRG	Lakefield Junction CT	Alternatives, Consequences to Society, Environmental Report
PL9/CN-98-0327	Lakehead	Clearbrook-Donaldson Oil Pipeline	Alternatives, Consequences to Society

Comments in Generation and Transmission Planning Proceedings

Docket No.	Company	Type	Subjects
E999/M-07-1028	All Utilities	Transmission	All Areas
ET9/RP-06-0605	SMMPA	Generation	Modeling
E001/RP-05-2029	Interstate Power	Generation	Modeling
E999/TL-05-1739	All Utilities	Transmission	All Areas
ET10/RP-05-1102	Missouri River	Generation	Modeling
ET2/RP-05-1100	Great River	Generation	Modeling
E017/RP-05-0968	Otter Tail Power	Generation	Modeling
E015/RP-04-0865	Minnesota Power	Generation	DSM, Supply
E002/RP-04-1752	Xcel Energy	Generation	Modeling, Nuclear, Bids
E999/TL-03-1752	All Utilities	Transmission	All Areas
ET2/RP-03-0974	Great River	Generation	DSM
E002/RP-02-2065	Xcel Energy	Generation	DSM, Nuclear
ET6/RP-02-1145	Minnkota	Generation	Forecasting, Contingency
E999/TL-01-0961	All Utilities	Transmission	All Areas
ET2/RP-01-0160	Great River	Generation	DSM
ET3/RP-00-1619	Dairyland	Generation	All Areas
E002/RP-00-0787	Xcel Energy	Generation	DSM, Nuclear
ET9/RP-00-0863	SMMPA	Generation	Forecasting
E015/RP-99-1543	Minnesota Power	Generation	DSM, Forecasting
E017/RP-99-0909	Otter Tail Power	Generation	Rate Design
ET10/RP-98-0938	Missouri River	Generation	Supply, Rate Design
ET2,3/RP-98-0366	CPA/Dairyland	Generation	Supply
E002/RP-98-0032	NSP	Generation	Supply, Nuclear
E015/RP-97-1545	Minnesota Power	Generation	DSM
E001/RP-97-0955	Interstate Power	Generation	Supply
ET9/RP-97-0954	SMMPA	Generation	Forecasting
ET7/RP-97-0001	United Power	Generation	DSM

Docket No. E002,ET2/CN-06-1115
OES Exhibit No. ___ (SRR-2)

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow Information Request No. 2
MN Department of Commerce
Date Received: October 31 , 2007

Question:

Please explain why the following conductors were chosen, as mentioned on pages 2.10 to 2.11 of the Petition:

a. a bundled conductor of two 954 ACSS cables for all proposed 345 kV transmission lines;
b. a single conductor, 795 ACSS cable for the proposed 230 kV transmission line; and
c. a single conductor, 795 ACSS cable for both proposed 161 kV transmission lines.

Response:

The size of conductor for the voltage classes of the lines proposed have become fairly standardized. In the early 1990s, Northern States Power Company ("NSP") sought to standardize the conductors it used on various transmission lines. The three projects under consideration in this proceeding have incorporated NSP's standardization work in their planning. The result of this standardization was to reduce life-cycle costs. This was done through 1) more closely matching line conductor capacity to the capacity of associated substation equipment, such as switches and breakers, 2) reducing impedance and, therefore system losses, and 3) controlling warehousing carrying costs by reducing the quantities of materials in emergency stock.

NSP also considered whether to use ACSR or ACSS conductors. Typically, an ACSS conductor can carry nominally 60 percent more power than identically-sized ACSR, but adds significantly less to the total project cost. As a result of this effort,

the ACSS conductor was selected as the standard for 345 kV, 230 kV, and 161 kV transmission lines.

Specific sized conductors were also chosen for each voltage. For 345 kV lines, the standard is a 954 ACSS bundled conductor. The most recent 345 kV project in the State, the Lakefield Junction to Split Rock 345 kV line, was constructed using the standard 954 ACSS bundled conductor. A bundled conductor is the standard because it reduces corona and audible noise. The 954 ACSS conductor is the standard because of its capacity (approximately 2,050 MVA), lower loss profile and minimal increased costs over the 795 ACSS conductor (approximately 1,860 MVA capacity) – in general, the step up from 795 ACSS to 954 ACSS results in approximately three percent increased project cost.

Twin Cities – Brookings County 345 kV Project:

The primary need studied in the Southwestern Minnesota Study was the need to increase generation outlet capability in Southwestern Minnesota. It was concluded that the 954 ACSS bundle conductor was the appropriate size because it would increase the power carrying capability, provide a lower impedance path, and have a lower losses profile than 795 ACSS.

The Twin Cities – Brookings County 345 kV Project also includes a 230 kV line from Hazel Creek Substation to Minnesota Valley Substation. The 795 conductor size is the most common size 230 kV conductor in service in the State. In essence, the proposal extends the existing 230 kV system that terminates in the Granite Falls area to the proposed Hazel Creek Substation. Since the existing 230 kV system uses the 795 conductor there would be no advantage to building the short connection to Hazel Creek to higher capacity standards.

Since filing the application, planning efforts have progressed. As noted in the Biennial Transmission Report, engineers are examining whether it makes sense to convert the existing 230 kV line from Granite Falls to the Twin Cities to 345 kV as the next step, after the CapX2020 Twin Cities – Brookings County 345 kV Project to increase transmission support to the Buffalo Ridge area. Consequently, the Applicants are re-evaluating the design of the Hazel Creek to Minnesota Valley segment of the CapX2020 proposal. The Department will be notified as soon as that examination is complete.

Twin Cities – Fargo 345 kV Project

The initial need driving the Twin Cities – Fargo 345 kV Project is to improve system reliability in the communities in the southern zone of the Red River Valley, the Alexandria area and the St. Cloud area. Study work indicated the 795 ACSS conductor could adequately serve the immediate needs to be addressed.

In the TIPS Update, the Forbes – Chisago 500 kV line was identified as the critical outage in the area as it pertains to loading on the Twin Cities – Fargo 345 kV line. The proposed project must be appropriately sized to make up for the capacity lost if the Forbes line were out of service. It is estimated that, immediately upon installation, the new Twin Cities – Fargo 345 kV line will carry 600 MVA of power during the loss of the Forbes line because it would be a strong path linking generation in Manitoba to the Twin Cities. Given demand growth patterns and significant wind resource potential in northwestern Minnesota and North Dakota, it is anticipated that the loading of this line will increase over time, justifying use of the higher capacity conductor.

Based on these near and longer-term needs, cost and the lower loss profile of a larger conductor, the 954 ACSS bundled conductor was chosen for construction of the Twin Cities – Fargo 345 kV line.

Twin Cities – La Crosse 345 kV Project

The initial need driving the Twin Cities – La Crosse 345 kV Project is also community service reliability. The electrical systems in the Rochester area and La Crosse require improvement to reliably meet the growing demand for power. In this case, study work also concluded that the 795 ACSS conductor could adequately address the immediate load-serving needs. However, the growth trend in these communities is expected to continue. Moreover, there is increasing interest in wind development in south-central and southeast Minnesota. Consistent with the long range comprehensive planning approach of the Vision Plan, there is also opportunity to connect the La Crosse line to power systems to the east or south in the future. It was concluded that the standard 954 ACSS bundled conductor, with its higher capacity and lower losses profile, would offer the best long-term system support.

For the 161 kV lines, the standard 795 ACSS conductor was chosen. A 795 ACSS conductor has a rating of 434 MVA. This conductor size (795) is the typical size used for 161 kV lines in the State. Additionally, planning engineers concluded

that this capacity rating was needed to provide system support in the event of a 345 kV line outage.

Response By:	Amanda King
Title:	Sr. Transmission Planning Engineer
Department:	Transmission Planning
Company:	Xcel Energy
Telephone:	612-330-5931
Date:	February 13, 2008

Response By:	Daniel Kline
Title:	Transmission Planning Engineer
Department:	Transmission Reliability & Assessment
Company:	Xcel Energy
Telephone:	612-330-7547
Date:	February 13, 2008

Response By:	Jared Alholinna
Title:	Senior Transmission Planning Engineer
Department:	Transmission Planning, Contracts & Strategy
Company:	Great River Energy
Telephone:	763-241-5797
Date:	February 13, 2008

2141642v1

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No. E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 3
Date Received: October 31, 2007

Question:

Regarding the list of underlying facilities in Figure 2-14 of the Petition, to the best of the Applicants knowledge, would the anticipated best solution for any of the overloaded facilities require a new (i.e., not reconductored or rebuilt to the same voltage) transmission line with either:

a. a capacity of 200 kV or more and greater than 1,500 feet in length in Minnesota; or
b. a capacity of 100 kV or more with more than ten miles of its length in Minnesota or that crosses a state line?

If so, please list the overloaded facility and associated the anticipated solution

Response:

At this time, 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 "a" or "b" above.

Response By: Jim Alders
Title: Manager Regulatory Products
Department: Government and Regulatory Affairs
Company: Xcel Energy
Telephone: 612-330-6732
Date: November 29, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 10
Date Received: October 31, 2007

Question:

On page 7.25 of the Petition the Applicants state:

> Compared with the cost of constructing 230 kV or 115 kV lines in addition to the Twin Cities – Fargo 345 kV line and given the length of time a 345 kV solution would effectively address the Alexandria-area voltage problems, the incremental cost of adding the termination at Alexandria is a reasonable solution to the existing issues.

Regarding this statement, please provide estimates of:

a. the cost of constructing the 230 kV or 115 kV lines;
b. the incremental cost of adding a termination at Alexandria; and
c. the length of time the 345 kV solution would effectively address the Alexandria-area voltage problems.

Response:

a. The 230 kV alternative would consist of a 230 kV transmission line from the Henning Substation to the Alexandria Substation that would be approximately 45 miles long and cost approximately $32.6 million. There would also be approximately $7.8 million in additional transformer and other substation costs at Alexandria Switching Station.

b. The incremental cost of adding a 345 kV line termination in the Alexandria area has been estimated to be approximately $12.5 million.

c. Based on currently forecasted load growth, the 345 kV solution for the Alexandria area has been forecasted to last until approximately 2050. The 230 kV

solution would effectively address the Alexandria-area voltage problems until approximately 2025.

Response By:	Daniel Kline
Title:	Transmission Planning Engineer
Department:	Transmission Reliability & Assessment
Company:	Xcel Energy
Telephone:	612-330-7547
Date:	November 29, 2007

2102467v4

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 18
Date Received: October 31, 2007

Question:

Please reconcile the differences between the $191.6 million cost estimate provided on page 145 of Appendix A-2 and the $330 to $360 million cost estimate provided on page 1.17 for the Twin Cities-La Crosse component of the proposed project.

Response:

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.

Response By: Grant Stevenson
Title: Senior Project Manager
Department: Xcel Energy Transmission
Company: Xcel Energy
Telephone: 612-330-6330
Date: December 4, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 19
Date Received: October 31, 2007

Question:

Please reconcile the differences between the $140 million installed cost estimate provided on page 56 of Appendix A-3 for the "South Source" option and the $390 to $560 million cost estimate provided on page 1.17 for the Twin Cities-Fargo component of the proposed project.

Response:

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.

Response By: Grant Stevenson
Title: Senior Project Manager
Department: Xcel Energy Transmission
Company: Xcel Energy
Telephone: 612-330-6330
Date: December 4, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 20
Date Received: October 31, 2007

Question:

Please reconcile the differences between the ($304 + $50=) $354 million cost estimates provided on pages 53 and 56 of Appendix A-4 and the $600 to $665 cost estimate provided on page 1.17 for the Twin Cities-Brookings County component of the proposed project.

Response:

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.

Response By: Kevin Lennon
Title: Manager Regional Transmission Projects
Department: Regional Transmission
Company Great River Energy
Telephone: 763-241-2216
Date: December 4, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 22
Date Received: October 31, 2007

Question:

Are the "Brookings Co – Yankee 115 kV #2" and "Brookings Co – Toronto 115 kV" lines mentioned on page 4 of Appendix A-4 of the Petition part of the Applicants' cost estimates and/or certification requests in this proceeding? If not, please explain why not.

Response:

The transmission system in the Buffalo Ridge area is comprised of lower voltage facilities that are internal to the Ridge (primarily 115 kV and lower voltage lines) and higher voltage lines that are external to the Ridge (*e.g.*, Lakefield Junction Substation – Split Rock Substation 345 kV line). The higher voltage lines are designed to transfer large amounts of power to the larger load centers to the east. The lower voltage lines are designed to provide access to the high voltage "bulk transmission system" lines. To use a transportation analogy, the higher voltage lines are the freeway and the lower voltages lines are the on-ramps to the freeway.

In analyzing options for further increasing generation outlet capability in the Buffalo Ridge area and points west in the Southwestern Minnesota Study, planning engineers made certain assumptions about where generation will likely develop and how to collect that power and connect it with the bulk transmission system. Planning engineers concluded that the Twin Cities – Brookings County 345 kV line is needed to provide additional capacity to move power from the Buffalo Ridge area to load centers to the east, primarily the Twin Cities. Planning engineers also identified two potential smaller voltage lines, on-ramps, to connect the generation with the bulk power system. These two lines were the Brookings County – Yankee 115 kV #2 line and the Brookings County – Toronto 115 kV line. Neither of these lines affects the level of generation outlet capacity that can be achieved by the Twin Cities –

Brookings County 345 kV Project. However, each of the lines provides additional opportunities for interconnection on the north end of the Ridge.

The Brookings County – Yankee 115 kV #2 line is part of the Buffalo Ridge Incremental Generation Outlet project which was approved in Docket No. E-002/CN-06-154, Order Granting Certificates of Need (Sept. 14, 2007). Xcel Energy anticipates filing a route application for this line by year end.

There are no current plans to construct the Brookings County – Toronto 115 kV line. Further improvements are needed around Buffalo Ridge to connect generators to the bulk power system, add transmission capacity, and address local system deficiencies. Depending on how much generation develops on the north end of the Ridge, this line may be constructed at a future date.

Response By:	Jared Alholinna
Title:	Senior Transmission Planning Engineer
Department:	Transmission Planning, Contracts & Strategy
Company:	Great River Energy
Telephone:	763-241-5797
Date:	December 10, 2007

2102485v3

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow — Information Request No. 23
MN Department of Commerce
Date Received: October 31, 2007

Question:

Page 4 of Appendix A-4 of the Petition states that "This option also coordinates with the planned Big Stone II generation addition and its identified interconnection facility additions." 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? If so, please list the necessary facilities.

Response:

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 Twin Cities – Brookings County 345 kV line is a major system connection that provides additional capacity to move power from the Buffalo Ridge area to the Twin Cities. The Twin Cities – Brookings County 345 kV Project is needed to relieve the power transfer limitation between the Ridge and the Twin Cities regardless of the other system additions that may be constructed along the Ridge. 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 to the levels demonstrated in the Southwestern Minnesota "EHV" study. Appendix A-4.

It is also known that with any significant increase in generation in the Buffalo Ridge area, the existing Ortonville to Morris 115 kV transmission line (which would be rebuilt as a 230 kV line as part of the Big Stone II outlet plan) would need to be upgraded in some fashion. This issue is addressed by the Big Stone II transmission facilities. Without the proposed Big Stone II transmission this issue would have to be addressed in some other way.

Response By:	Tim Rogelstad
Title:	Manager
Department:	Delivery Planning
Company:	Otter Tail Power Company
Telephone:	218-739-8583
Date:	December 4, 2007

2108843v7

RECEIVED
DEC 24 2007
MN Dept of Commerce

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 24
Date Received: October 31, 2007

Question:

Page 7 of Appendix A-4 of the Petition states

> there is no 'reconductor only' option because it is known that this strategy was exhausted in the BRIGO development, as also confirmed in the MISO interconnection studies (Group 2 and Group 3) for proposed Buffalo Ridge generation additions.

Regarding this statement, please provide a copy of the relevant sections of the MISO interconnection studies (Group 2 and Group 3) if available.

Response:

At the time of the Southwestern Minnesota Study (Appendix A-4), the individual interconnection studies for the Group 2 generation projects had been completed and the results had been consolidated into the "Draft Final Report Coordinated Studies #2 – Sensitivity Studies to Resolve Local and Regional Stability Limitations" ("Group 2 Studies").

Individual interconnection studies had also been completed for Group 3 projects. *See e.g.,* Final Report, Generation Interconnection Study – Project #G426 100 MW Wind Farm in Dickinson County, IA MISO Queue # 3811-01 ("G426 Study"). The results of the Group 3 individual studies were never consolidated into a "Coordinated Studies" report.

The G426 Study is typical of other individual interconnection studies that showed numerous lines with overloads exceeding 200 percent of nominal ratings. *See* G426 Study, Tables 3.6 and 3.8. While reconductoring is a system improvement that can

address overloads, the appropriateness of reconductoring is line specific and typically not a practical option if the overload exceeds 200 percent. In such cases, a much higher capacity conductor must be used for reconductoring. When these larger capacity conductors are loaded to their nominal ratings or beyond, they have much higher loss profiles than lower capacity conductors of the same voltage. The benefits of reconductoring a line to achieve an increase of more than 200 percent of the nominal rating of the existing line is offset by the higher losses profile of the larger conductor under high loading conditions. To avoid these system losses, it is typically more appropriate to build a new line or rebuild the existing line at a higher voltage to achieve the same capacity with lower losses.

Attached is a CD, Bates No. CapX2020 000003, which contains all of the Group 2 study information that is posted on MISO's website. Pages 2 and 3 of the study report explain the reasons for not correcting the steady state base case overloads by reconductoring. The CD also contains the G426 Study.

Response By:	Jason Standing
Title:	Specialty Engineer
Department:	Transmission Reliability and Asset Management
Company:	Xcel Energy
Telephone:	612-330-7768
Date:	December 21, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow — Information Request No. 27
MN Department of Commerce
Date Received: October 31, 2007

Question:

Please explain the peer-review process at Mid-continent Area Power Pool/Midwest Reliability Organization/Midwest ISO that the engineering studies in Appendices A-1 to A-4 went through.

Response:

All of the utilities in the Mid-continent Area Power Pool ("MAPP") region participate in Sub-regional Planning Groups ("SPGs") that address issues in their areas. These meetings are a chance for utilities to bring forward projects and discuss potential planning issues. These meetings are open to the public. Various generation developers, interested public parties, Public Utilities Commission staff members and Department of Commerce staff members have historically attended these meetings.

Each of the engineering studies in Appendices A-1 through A-4 was presented to both the Missouri Basin SPG and the Northern MAPP SPG multiple times. Typically, when a study is brought through the SPG process, it is presented once at the start of the study process. For some large studies, a list of interested parties is gathered and these people receive occasional study updates as public study information becomes available. Another presentation typically occurs when the actual modeling (power flow and dynamic stability) study work is completed, and a third presentation may occur once the study is completed and ready to be published.

For any regional transmission project proposed by a member utility, the Midwest ISO conducts a separate and independent review for its own transmission expansion plan ("MTEP"). This review is closely coordinated with the utilities proposing the project. Midwest ISO's analysis includes an examination of study assumptions and involves power flow study work which details the impact of the project on the Midwest ISO transmission grid and the Midwest ISO market.

The Midwest ISO is currently reviewing all three of the projects proposed in this application.

Response By:	Daniel Kline
Title:	Transmission Planning Engineer
Department:	Transmission Reliability & Assessment
Company:	Xcel Energy
Telephone:	612-330-7547
Date:	November 29, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow — Information Request No. 28
MN Department of Commerce
Date Received: October 31, 2007

Question:

Please provide a CD of the spreadsheet showing hourly, real-time prices at the Minnesota hub as discussed in Appendix D-9 of the Petition.

Response:

The information requested is enclosed on CD, Bates No. CapX2020 0000004.

Response By: Jim Alders
Title: Manager Regulatory Projects
Department: Government and Regulatory Affairs
Company: Xcel Energy
Telephone: 612-330-6732
Date: November 29, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 29
Date Received: October 31, 2007

Question:

Regarding the CapX northwest line, treating a Maple River-Alexandria-Western St. Cloud-Benton County line as the base case (zero cost, zero losses), please provide the estimated incremental capital cost, on-peak line losses, and off-peak line losses associated with the Maple River-Alexandria-Western St. Cloud-Sherburne County alternative.

Response:

The Maple River-Alexandria-Western St. Cloud-Sherburne alternative and the Maple River-Alexandria-Western St. Cloud-Benton County alternative are both 345 kV transmission line proposals that provide similar electrical performance. They would use the same structures and conductors and have geographically similar endpoints. As a result, the losses profiles of both options are similar.

The cost profiles of the two configurations, assuming overhead construction, are also comparable. For the Maple River -Benton County configuration, the estimated range is $390 to $530 million. For the Maple River-Sherburne County configuration, the estimated range is $390-$550 million. These estimates are dependent upon the ultimate route selected, either the direct route along Interstate 94, or a more indirect route away from the interstate.

Response By: Warren Hess
Title: Senior Planning Engineer
Department: Transmission Asset Management
Company: Xcel Energy

Telephone:	612-330-6311
Date:	November 29, 2007

Response By:	Grant Stevenson
Title:	Senior Project Manager
Department:	Xcel Energy Transmission
Company:	Xcel Energy
Telephone:	612-330-6330
Date:	November 29, 2007

2102490v2

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow — Information Request No. 30
MN Department of Commerce
Date Received: October 31, 2007

Question:

Regarding the CapX northwest line, treating a Maple River – Alexandria-Western St. Cloud – Benton County line as the base case (zero cost, zero losses), please provide the estimated incremental capital cost, on-peak line losses, and off-peak line losses associated with the Maple River – Alexandria-Western St. Cloud – Monticello alternative.

Response:

The proposed Maple River – Alexandria – Western St. Cloud-Monticello and the Maple River – Alexandria – Western St. Cloud – Benton County alternative are both 345 kV transmission line proposals that would provide similar electrical performance. They would use the same structures and conductors and have geographically similar endpoints. As a result, the losses profiles of both options are similar.

The cost profiles of the two configurations, assuming overhead construction, are also comparable. For the Maple River – Benton County configuration, the range is $390 to $530 million. For the Maple River – Monticello configuration, the range is $390 to $560 million. These estimates are dependent upon the ultimate route selected, either the direct route along Interstate 94, or a more indirect route away from the interstate.

Response By: Warren Hess
Title: Senior Planning Engineer
Department: Transmission Asset Management
Company: Xcel Energy

Telephone:	612-330-6311
Date:	November 29, 2007

Response By:	Grant Stevenson
Title:	Senior Project Manager
Department:	Xcel Energy Transmission
Company:	Xcel Energy
Telephone:	612-330-6330
Date:	November 29, 2007

2102491

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow — Information Request No. 31
MN Department of Commerce
Date Received: October 31, 2007

Question:

Regarding the CapX southeast line, assuming a Hampton Corner-North Rochester-(Winona crossing)-North La Crosse line as the base case (zero cost, zero losses), please provide the estimated incremental capital cost, on-peak line losses, and off-peak line losses associated with the Hampton Corner-North Rochester-(La Crescent crossing)-La Crosse alternative.

Response:

The proposed Hampton Corner – North Rochester (Winona crossing) – North La Crosse and the alternative Hampton Corner – North Rochester (La Crescent crossing) – La Crosse alternative are both 345 kV transmission line proposals, would use the same structures and conductors and have geographically similar endpoints. As a result, the losses profiles of both options are comparable.

The cost profiles of the two configurations, assuming overhead construction, are also comparable. The proposed Hampton Corner – North Rochester (Winona crossing) – North La Crosse is estimated to cost approximately $340 million. The alternative Hampton Corner – North Rochester (La Crescent crossing) – La Crosse alternative is estimated to cost approximately $330 million.

Response By: Warren Hess
Title: Senior Planning Engineer
Department: Transmission Asset Management
Company: Xcel Energy

Telephone:	612-330-6311
Date:	November 29, 2007

Response By:	Grant Stevenson
Title:	Senior Project Manager
Department:	Xcel Energy Transmission
Company:	Xcel Energy
Telephone:	612-330-6330
Date:	November 29, 2007

2102492v1

DEC 24 2007
Dept of Commerce

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow — Information Request No. 32
MN Department of Commerce
Date Received: October 31, 2007

Question:

Regarding the CapX southwest line, assuming the proposed Lyon County – Franklin-Helena line with a Lyon County – Hazel Creek-Minnesota Valley spur as the base case (zero cost, zero losses), please provide the estimated incremental capital cost, on-peak line losses, and off-peak line losses associated with the Lyon County – Hazel Creek-Minnesota Valley – West Waconia-Helena alternative.

Response:

To clarify and supplement the information provided in the Application, descriptions of the proposal and the "West Waconia Alternative" are provided below, along with the requested information.

The proposed Twin Cities – Brookings County 345 kV Project consists of a single circuit 345 kV line from Brookings County Substation to Lyon County Substation, a double circuit 345 kV line from Lyon County Substation to Franklin Substation to Helena Substation, a single-circuit 345 kV line from Helena Substation to Lake Marion Substation to Hampton Corner Substation, a single circuit 345 kV line from Lyon County Substation to Hazel Creek Substation and a 230 kV line from Hazel Creek Substation to Minnesota Valley Substation.

The West Waconia Alternative is a modification of an alternative studied in the Southwestern Minnesota Study. In the Southwestern Minnesota Study, planning engineers considered a "System Alternative Revised" which had the following configuration: a single circuit 345 kV line from Brookings County Substation to Lyon County Substation to Minnesota Valley Substation to West Waconia Substation to Blue Lake Substation and a single circuit 345 kV line from West Waconia Substation to Helena Substation to Lake Marion Substation and Hampton Corner Substation.

After the Southwestern Minnesota Study was completed, CapX2020 planning engineers developed the West Waconia Alternative. This alternative does not include the West Waconia – Blue Lake 345 kV connection, but does include a Hazel Creek – Minnesota Valley 230 kV line.

This alternative would generally bypass the Franklin Substation and parallel the existing 230 kV line between Minnesota Valley Substation and the Blue Lake Substation. Specifically, the West Waconia Alternative consists of a single circuit 345 kV line from Brookings County Substation to Lyon County Substation to Hazel Creek Substation to West Waconia Substation to Helena Substation to Lake Marion Substation to Hampton Corner Substation and a 230 kV line from Hazel Creek Substation to Minnesota Valley Substation.

The losses profile of the West Waconia Alternative is inferior to that of the proposed Twin Cities – Brookings County 345 kV Project. Relative to the proposed project, the West Waconia Alternative has an estimated 91 MW of loss increase during on-peak periods and 101 MW loss increase during off-peak periods.

The cost profiles of the two configurations, the Twin Cities – Brookings County 345 kV Project and the West Waconia Alternative, assuming overhead construction, are similar. The proposed Twin Cities – Brookings County 345 kV Project is estimated to cost between approximately $600 and $665 million depending on the route selected. The West Waconia Alternative is estimated to cost approximately $615 million.

Since the West Waconia Alternative was identified, events have occurred and continue to occur that may impact the appropriateness of this alternative. At the time of the Southwestern Minnesota Study, planning engineers made certain assumptions about the demand for wind generated power from the west based on the then governing renewable energy objectives. In 2007, the Renewable Energy Standard ("RES") legislation became law. The RES law has dramatically increased the demand for transmission service to deliver wind-generated power necessary to meet the standards. The Twin Cities – Brookings County 345 kV line alone will not be sufficient to meet these increased needs for generation outlet from western Minnesota.

Additional analyses are currently underway to identify additional transmission improvements to provide additional generation outlet capability. One of the potential transmission projects is a system upgrade of the 230 kV Minnesota Valley – Blue Lake transmission line. Past transmission studies have repeatedly concluded that the existing line limits transfer capability from the western portion of Minnesota to the Twin Cities. A study, estimated to be completed in 2008, will focus on identifying

transmission alternatives that will eliminate this constraint, thus allowing more renewable generation development in the Buffalo Ridge Area. One alternative that will be explored is rebuilding the Minnesota Valley – Blue Lake 230 kV line to a higher voltage.

Should planning engineers conclude that this alternative is the best alternative to address the limitation, the West Waconia Alternative for the Twin Cities – Brookings County 345 kV Project would be less desirable because it would result in a high concentration of bulk transmission lines along the Minnesota Valley Substation – West Waconia Substation corridor. As currently envisioned, the two lines would likely be placed in relatively close geographic proximity, potentially as close as sharing common (parallel) rights-of-way. While the two circuits would be treated separately in system analyses, that is, the loss of both lines would not be assumed in an N-1 analysis, the risk of an outage of both lines increases due to a storm or other event, placing the system at risk of instability due to the loss of multiple major transmission lines.

Response By:	Warren Hess
Title:	Senior Planning Engineer
Department:	Transmission Asset Management
Company:	Xcel Energy
Telephone:	612-330-6311
Date:	December 21, 2007

Response By:	Jared Alholinna
Title:	Senior Transmission Planning Engineer
Department:	Transmission, Planning, Contracts & Strategy
Company:	Great River Energy
Telephone:	763-241-5797
Date:	December 21, 2007

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow Information Request No. 38
MN Department of Commerce
Date Received: November 13, 2007

Question:

Regarding the CapX southeast line, would using the Prairie Island end point, considering the likely routing option(s), result in the Prairie Island – North Rochester line and the Prairie Island – Byron line being considered as a single line for purposes of determining N-1 scenarios?

If yes, please explain the consequences of the two lines being treated as one in terms of the proposed needs.

Response:

There is an existing 345 kV circuit between Prairie Island and Byron Substation just west of Rochester. Rochester relies on the Byron Substation as its main electrical connection to the power supply system. There are some circumstances in which the proposed 345 kV line to North Rochester is needed to maintain reliable service if the existing Prairie Island – Byron circuit fails. If both circuits were to fail at the same time, electrical service to Rochester area customers would be at risk.

If the proposed 345 kV circuit to North Rochester were terminated at Prairie Island, the alignment of the existing Prairie Island – Byron line would be a prime candidate for routing.

Technically, the new line and the existing Prairie Island – Byron line would be considered a single line only if both circuits were on the same set of structures, that is if the existing circuit were replaced with a double circuit line. In such a case, the N-1 failure would be the loss of the Prairie Island – Byron / Prairie Island – North Rochester double circuit line.

If the proposed line were routed immediately adjacent to the existing line, the two circuits could be less than 100 feet apart, for most if not all of the 40 miles between Prairie Island and Rochester. While the two circuits would be treated separately in

system analyses, that is, the loss of both lines would not be assumed in an N-1 analysis, the risk of loss of both circuits due to storm damage would remain.

The proposed Hampton Corner configuration reduces the risk of losing both circuits and therefore increases system reliability. The new 345 kV line would be geographically separated from the existing Prairie Island – Byron 345 kV line, thereby reducing the potential that both 345 kV lines would fail due to a single storm event. Indeed, any route that maximizes the distance between the new 345 kV line and the Prairie Island – Byron line will reduce outage risk. Reliability will be further enhanced by the addition of breakers at the Hampton Corner Substation which will provide additional electrical separation between the two 345 kV lines. With this configuration, if one of the lines were to fail, the other could continue to serve the Rochester area.

Response By:	Amanda King
Title:	Sr. Transmission Planning Engineer
Department:	Transmission Planning
Company:	Northern States Power Company
Telephone:	612-330-5931
Date:	December 4, 2007

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow — Information Request No. 40
MN Department of Commerce
Date Received: January 10, 2008

Question:

Appendices C6 and C7 of the petition calculate a generation interconnection need of several thousand MW. The applicants' proposal represents a first step towards meeting the proposed need, but appears unlikely to meet the entire need. The following questions are intended to explore accelerating subsequent steps towards meeting the proposed need.

1. Regarding the Applicants' discussion of constructing the Twin Cities—Fargo line to a higher voltage (Section 7.1.1 of the petition), please assume a goal of 1) moving increased quantities of hydroelectric energy from Manitoba to Minnesota's load centers, and 2) building a new 500 kV transmission line from Winnipeg to Fargo-Moorhead (for example, Dorsey-Maple River). Under such conditions:

   A. Would building all or part of the Twin Cities—Fargo line to 500 kV standards (but operating at 345 kV until a hypothetical Dorsey-Maple River 500 kV line is constructed) pass a screening test?

   B. If the answer to part A is yes, please provide an estimate of the capital cost for building all or part (as appropriate) of the Twin Cities—Fargo line to 500 kV standards (but operating at 345 kV).

   C. If the answer to part A is yes, please provide:

      i. The on-peak and off-peak losses when built and operated at 500 kV (i.e., with a Winnipeg to Fargo-Moorhead 500 kV line) in a manner comparable to Figure 5-10 on page 5.27 of the Petition; and

      ii. The on-peak and off-peak losses when built at 500 kV but operated at 345 kV (i.e., without a Winnipeg to Fargo-Moorhead

500 kV line) in a manner comparable to Figure 5-10 on page 5.27 of the Petition.

2. Regarding the Applicants' discussion of constructing the Twin Cities—Brookings County line to a higher voltage (Section 7.1.1 of the petition), please assume a goal of 1) moving increased quantities of wind energy from Buffalo Ridge to Minnesota's load centers, and 2) rebuilding the Minn Valley-Panther 230 kV line to 345 kV (see page 37 of Appendix A4 of the petition: "it is fairly evident that a replacement would naturally be some type of 345 kV construction;" if the Applicants have better information regarding the likely future of this line please use that better information in your response.).

   A. Under such conditions would building all or part of the Twin Cities—Brookings County line to 500 kV standards (but operating at 345 kV until a hypothetical Minn Valley-Panther rebuild to higher voltage is constructed) pass a screening test?

   B. If the answer to part A is yes, please provide an estimate of the capital cost for building the Twin Cities—Brookings County line (or appropriate segments) to 500 kV standards.

   C. If the answer to part A is yes, please provide:

      i. The on-peak and off-peak losses when built and operated at 500 kV (i.e., with a Minn Valley-Panther rebuild to higher voltage) in a manner comparable to Figure 5-10 on page 5.27 of the Petition; and

      ii. The on-peak and off-peak losses when built at 500 kV but operated at 345 kV (i.e., without a Minn Valley-Panther rebuild to higher voltage) in a manner comparable to Figure 5-10 on page 5.27 of the Petition.

Response:

1.

A. In order to address this question, the performance of the Twin Cities – Fargo line was evaluated with respect to the summer on-peak incremental transfer capability from North Dakota to the Twin Cities under the following three construction and operation scenarios: (1) 345 kV construction/345 kV operation (the proposed 345 kV line), (2) 500 kV construction/345 kV operation, and (3) 500 kV construction/500 kV operation. The system intact and first-contingency analysis was performed using the MUST – PSS™E Power System Simulator for Managing and Utilizing System Transmission. MUST is used to perform automated contingency analysis while progressively incrementing power transfer. For purposes of the study, 1,250 MW of additional generation near Winnipeg was presumed.

Comparing the 500 kV construction/345 kV operation scenario to the proposed 345 kV line, the same limiters (overloads) are encountered, some at slightly lower transfer levels and some at slightly higher transfer levels. In either case, all limiters at higher transfer levels are due to outages of the new line segments, so the voltage of the line is largely irrelevant. Consequently a single transmission build out with 500 kV design does not attain any significant transfer capability increase as compared to the transfer level attained with the proposed 345 kV line configuration. In fact, results of the 500 kV construction/500 kV operation scenario analysis identified approximately four new underlying system overloads that would require mitigation in order to achieve the same transfer levels attained by the proposed 345 kV line.

Two previous regional transmission planning studies (the Northwest Exploratory Study and the CapX2020 Vision Study) have also considered the question of whether 500 kV or 345 kV regional development is more appropriate. As Manitoba Hydro continues to show interest in developing its available hydroelectric resources, these studies have examined ways to efficiently deliver increased amounts of hydroelectric generation. The Northwest Exploratory Study and the Vision Study concluded that these two lines would be required in order to achieve a large increase (approximately 2,000 MW) in power transfer capability. Specifically, to access increased generation development in North Dakota and import the hydroelectric resources available from Manitoba, both a 500 kV line from the Twin Cities to Winnipeg and a 345 kV line from the Twin Cities to Fargo are necessary first steps in transmission system reinforcement. (For the Fargo to Twin Cities connection, the amount of achievable power transfer capability did not significantly differ for 345 kV and 500 kV configurations).

Completing the Fargo – Twin Cities 345 kV line first will provide load-serving benefits to the communities in the southern Red River Valley, including Alexandria, and St. Cloud. In combination with a future Winnipeg – Fargo 500 kV line, this line will also provide a valuable backup path for the power flowing on the existing Manitoba – U.S. 500 kV line. Should future generation development warrant, completion of a second Manitoba – U.S. 500 kV line could be completed via the Fargo area. Regardless, the important take away from this and previous study work is that two lines are required to achieve the transfer levels necessary for significant wind and hydroelectric generation development.

Constructing the Twin Cities – Fargo line at 500 kV and operating at 345 kV is also not a reasonable option because it would not provide additional load serving capability or improve overall system performance. Construction at 500 kV (with 345 kV operation) only slightly lowers the line impedance when compared to the impedance of the proposed 345 kV line. As mentioned above, this lower impedance results in a few additional underlying system limitations that must be mitigated to pursue 500 kV operation prior to having a second 345 kV line in service. Additionally, system dynamic stability would not improve in a 500 kV construction scenario (either 345 kV or 500 kV operation) because the stability performance is limited by an outage of the new line during high transfer levels.

Without considering the additional capital costs, building the proposed Twin Cities – Fargo line to 500 kV standards passes a screening test, but as a lone project proposal, it offers very limited benefits over the proposed 345 kV line.

B. The estimated total cost increase to substations and transmission lines for a single circuit 500 kV design is $133,000,000 or roughly a 34% increase over the $390,000,000 estimate for the single circuit 345 kV design, assuming the shorter route, provided in the Application (Application at 2.17).

C. The following two tables show the requested losses analyses (under system intact conditions) for 345 kV and 500 kV operating scenarios. The first case includes a Winnipeg to Fargo-Moorhead 500 kV line. The second case does not.

i.

Winnipeg to Twin Cities (Additional Transfer)	0 MW Transfer		1250 MW Transfer		0 MW Transfer		1250 MW Transfer	
Configuration	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)
Three Proposed 345 kV Projects with Dorsey-Fargo 500 kV	17820	N/A	18120	N/A	17596	N/A	17860	N/A
Twin Cities-Fargo Built to 500 kV Stds 500 kV Operation with Dorsey-Fargo 500 kV	17784	36	18030	90	17573	23	17805	56
Twin Cities-Fargo 500 kV and 345 kV with Dorsey-Fargo 500 kV	17774	46	18009	111	17568	28	17791	69

ii.

Fargo to Twin Cities (Additional Transfer)	0 MW Transfer		1000 MW Transfer		0 MW Transfer		1000 MW Transfer	
Configuration	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)
Three Proposed 345 kV Projects	17852	N/A	18009	N/A	17624	N/A	17806	N/A
Twin Cities-Fargo Built to 500 kV Stds 345 kV Operation	17849	4	17999	10	17621	3	17799	7
Twin Cities-Fargo Built to 500 kV Stds 500 kV Operation	17833	20	17946	63	17613	11	17770	36
With Twin Cities-Fargo 500 kV and 345 kV	17827	26	17927	82	17610	14	17760	46

2.

A. In order to address this question, the performance of the Twin Cities – Brookings County line was evaluated with respect to the summer off-peak incremental transfer capability from Buffalo Ridge to the Twin Cities under the following two construction and operation scenarios: (1) 345 kV construction/345 kV operation (the proposed 345 kV line) and (2) 500 kV construction/345 kV operation. The system intact and first-contingency analysis was performed using the MUST – PSS™E Power System Simulator for Managing and Utilizing System Transmission. MUST is used to perform automated contingency analysis while progressively incrementing power transfer.

Upon conducting the screening analysis on a single-circuit 500 kV line, operated at 345 kV, it was determined that the end-to-end impedance of this line is higher than that of the proposed 345 kV line. This results in increased inadvertent flow (loop flow) through Manitoba and other remote systems. Losses are slightly higher for this single-circuit 500 kV configuration. This higher losses profile is due to the fact that 500 kV lines are typically constructed with three conductors per phase per circuit

whereas the proposed 345 kV design will have the two conductors per phase per circuit. (The Lyon County – Franklin – Helena segment will be double-circuit construction.)

Based on this analysis and in comparing the 500 kV construction/345 kV operation scenario to the proposed 345 kV line, two new limiters (overloads) are encountered and one limiter is eliminated. The 500 kV scenario also has limiters which are encountered at significantly lower transfer levels. Consequently, if the new Twin Cities – Brookings County line were built as a single-circuit 500 kV, these additional two new limiters would need to be addressed. An alternative would be to add series compensation to the 500 kV lines at an estimated cost of $60 million to make its impedance equivalent to that achieved with the proposed 345 kV (double-circuit) line.

Without considering the additional capital costs, building the proposed Twin Cities – Brookings County line to 500 kV standards passes a screening test, but creates the need for additional system improvements without providing any significant transfer capability beyond that provided by the proposed 345 kV project. Additionally, constructing the line to 500 kV standards and operating at 500 kV does not result in significant loss reduction or additional transfer capability over the proposed 345 kV line project.

B. 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 or roughly a 30% increase.

C. The following two tables show the requested losses analyses (under system intact conditions) for 345 kV and 500 kV operating scenarios. The first case assumes the Minn Valley – Blue Lake 230 kV line is rebuilt to double-circuit 345 kV. The second case assumes there is no Minn Valley – Blue Lake 230 kV rebuild.

i.

Buffalo Ridge to Twin Cities	1200 MW Transfer		2400 MW Transfer		1200 MW Transfer		2400 MW Transfer	
Configuration	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)
Three Proposed 345 kV Projects with MN Valley-Blue Lake Rebuild	17811	N/A	18093	N/A	17624	N/A	17813	N/A
Twin Cities-Brookings Cty built to 500 kV Stds 345 kV Operation with MN Valley-Blue Lake Rebuild	17817	-7	18109	-16	17629	-5	17825	-12
Twin Cities-Brookings Cty built to 500 kV Stds 500 kV Operation with MN Valley-Blue Lake Rebuild	17803	8	18067	26	17618	6	17794	19

ii.

Buffalo Ridge to Twin Cities	1200 MW Transfer		2400 MW Transfer		1200 MW Transfer		2400 MW Transfer	
Configuration	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total On-Peak Model Losses (MW)	Total On-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)	Total Off-Peak Model Losses (MW)	Total Off-Peak Loss Benefit (MW)
Three Proposed 345 kV Projects w/o MN Valley-Blue Lake Rebuild	17852	N/A	18202	N/A	17651	N/A	17885	N/A
Twin Cities-Brookings Cty built to 500 kV Stds 345 kV Operation w/o MN Valley-Blue Lake Rebuild	17875	-23	18233	-31	17669	-17	17920	-35
Twin Cities-Brookings Cty built to 500 kV Stds 500 kV Operation w/o MN Valley-Blue Lake Rebuild	17845	7	18179	23	17647	4	17869	15

Response By:	Daniel Kline, PE (Part 1)
Title:	Transmission Planning Engineer
Department:	Transmission Reliability & Assessment
Company:	Xcel Energy
Telephone:	612-330-7547
Date:	April 7, 2008

Response By:	Jared Alholinna (Part 2)
Title:	Engineer
Department:	Transmission
Company:	Great River Energy
Telephone:	763-241- 5797
Date:	April 7, 2008

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Steve Rakow, MN Department of Commerce — Information Request No. 44
Date Received: February 20, 2008

Question:

Regarding the economic analysis of losses discussed in section 12.8 of Appendix A-2 (page 162) of the Petition, please confirm that the loss data for both the 345 kV preferred alternative and the hypothetical 161 kV alternative does not exist. Alternatively, please provide the loss data for both alternatives.

Response:

The 2005 Rochester/La Crosse Study did not include information regarding losses. An analysis was undertaken to calculate the losses requested, recognizing that the Twin Cities – La Crosse 345 kV Project has evolved since the original study work was completed. Also, our knowledge of the transmission system has, understandably, improved as the in-service date is nearer. With this in mind, instead of providing the loss analysis on the original 2009 Summer Peak from the *2003 MISO Model dated January 2003* used in the Rochester/La Crosse Study, we chose to use a more updated model – the 2011 Summer Peak from the *2006 MAPP Series*. The following are some of the transmission infrastructure improvements contained in the 2011 Summer Peak model that the original studied model lacked:

- Arrowhead-Gardner Park 345 kV line
- Monroe County 60 MVAR 161 kV Capacitor
- La Crosse (2) 60 MVAR 161 kV Capacitors
- Hillsboro 30.24 MVAR 161 Capacitor
- Monroe County Council Creek 161 kV line
- Genoa-Coulee 161 kV Upgrade
- La Crosse Area Load 504 MW (494 MW in the 2009 Summer Peak case)

The base case is titled sp11basea. The 345 kV alternative was created by using the configuration employed in the original study[1] except the North Rochester 345/161 kV substation taps the Prairie Island-Byron 345 kV line to better match the proposed configuration. The 345 alternative case is named sp11basea-345 alt. The 161 kV alternative has the same configuration as the original study.[2]

The losses of three cases were compared:

Case	Name	Case Loses MW	Delta MW (Loss Decrease)
Base Case	sp11basea	12,758.1	-----
345 Alternative Case	sp11basea-345-alt	12,747.6	10.5
161 Alternative Case	sp11basea-161-alt	12,751.1	7.0

A similar method was used for the summer off peak case. The model used for this analysis is the 2011 Summer Off Peak from the *2006 MAPP Series*. High west to east transfers were added to the base case until MWSI reached 1,508 MW (Prairie Island-Byron – 832 MW and Eau Claire-Arpin – 676 MW). Both the 345 Alternative and the 161 Alternative were created the same as the in the summer peak case described above.

The losses of three cases were compared:

Case	Name	Case Loses MW	Delta MW (Loss Decrease)
Base Case	sop11basea	12,216.2	-----
345 Alternative Case	sop11basea-345-alt	12,191.8	24.4
161 Alternative Case	sop11basea-161-alt	12,211.3	4.9

---

1 Southeastern Minnesota-Southwestern Wisconsin Reliability Enhancement Study; Woodworth 3-6-2006.

2 La Crosse 161 kV Load Serving Study; Iverson 8-3-2005. Found in Chapter 9 of Rochester/La Crosse Study.

Response By:	Jerry Iverson
Title:	Planning Engineer III
Department:	Power Delivery
Company:	Dairyland Power Cooperative
Telephone:	608-787-1390
Date:	April 7, 2008

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002/RP-07-1572
Response To: Dept of Commerce Information Request No. 10
Date Received: February 8, 2008

Question:

Please provide the total tons of Carbon Dioxide emitted by Xcel's system in 2005.

Response:

The NSP-M Company Carbon Dioxide emissions for 2005 are as follows:

	NSP-M	NS-W	NSP
Total CO2 tons	23,447,696	4,742,504	28,190,200

Response By: David P. Chapman
Title: Environmental Analyst
Department: Audit, Issues
Telephone: 806-378-2592
Date: February 19, 2008

Rakow

State of Minnesota
OFFICE OF ENERGY SECURITY

Utility Information Request

Docket Number: ET3/RP-08-113

Date of Request: February 25, 2008

Requested From: Ray Sand
Dairyland Power Cooperative

Response Due: March 06, 2008

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
1	Please provide the total tons of Carbon Dioxide emitted by Dairyland's system in 2005.

Dairyland calculates its carbon dioxide emissions at 1.005 tons per MWh for coal and 0.45 tons per MWh for gas-fired generation.

For 2005, these figures are 4,973,686 tons and 5,738 tons respectively. The total is 4,979,424.

Response by: Raymond Sand

Title: Economist/Forecaster

Department: Planning Services

Telephone: 608-787-1208

List sources of information:

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Elizabeth Goodpaster, Wind on the Wires, et al — Information Request No. 2
Date Received: January 9, 2008

Question:

The CapX2020 Group I projects Certificate of Need Application ("Application") does not appear to include all the underlying transmission upgrades associated with the Brookings – Twin Cities 345 kV line that were identified as needed to achieve the full 1900 megawatt capacity on the proposed Brookings – Twin Cities transmission line, in the "Southwestern Minnesota – Twin Cities EHV Development Electric Transmission Study" (November 9, 2005), Section 8, p. 39-40.

(a) Please identify all of the underlying transmission upgrades needed to achieve the full 1900 MW capacity of the Brookings – Twin Cities 345 kV line are included in the Application and those that have been excluded.
(b) If the Application does not include all of the necessary underlying upgrades, please explain why.
(c) To the extent that the underlying transmission upgrades needed to achieve the full 1900 MW capacity on the Brooking – Twin Cities 345 kV line have been excluded from the Application, please identify and describe the plan to complete the underlying transmission upgrades and anticipated timing for such. (*Identify and describe the plan and timing on both underlying upgrades that require a Certificate of Need as well as upgrades that do not require a Certificate of Need.*)

Response:

The Application describes an outlet level of approximately 1,800 to 1,900 MW that could be achieved by construction of the Twin Cities – Brookings County 345 kV Project. The Project is based on analyses completed in the Southwestern Minnesota – Twin Cities EHV Development Electric Transmission Study ("Southwestern Minnesota Study"). (Appendix A-4.) In the Southwestern Minnesota Study, certain generation patterns comprising the 1,800 to 1,900 MW were assumed for the Buffalo Ridge Area and facilities needed to achieve these levels were identified. Those facilities are listed in Section 8 of the Southwestern Minnesota Study and included a

reconductoring of the Minnesota Valley – Panther – McLeod 230 kV transmission line.

Since the completion of the Southwestern Minnesota Study, the Renewable Energy Standard ("RES") legislation was enacted, new facilities have been added to the electrical system and further analysis has been undertaken to identify improvements that could provide significantly more outlet capability in Southwestern Minnesota. Additional studies are currently underway to identify additional transmission improvements to provide additional generation outlet capability.

The limiter preventing further development of outlet capability is the Minnesota Valley – Panther – McLeod – Blue Lake 230 kV line. In the Southwestern Minnesota Study, the plan was to reconductor the line to increase its capacity. Planning engineers have concluded that given the dramatic increase in demand for renewable generation created by the RES, the entire Minnesota Valley – Panther – McLeod – Blue Lake 230 kV line should be replaced by or upgraded to 345 kV, potentially double circuited, to allow more generation development in the Buffalo Ridge Area.[1] It is anticipated that study work will be completed in 2008 with a Certificate of Need application being filed shortly thereafter. When this rebuild project is complete, generation outlet capability could exceed 3,000 MW.

As a result of these events, the list of facilities for the Twin Cities – Brookings County 345 kV Project has been adjusted. A list of the facilities that are part of the Twin Cities – Brookings County 345 kV Project are shown on Exhibit 1, attached. When the Exhibit 1 facilities have been constructed, outlet capability in the Buffalo Ridge Area is expected to reach 1,800 to 1,900 MW.

There are three significant modifications to the list, as follows:

- The 115 kV transmission lines, Brookings County – Yankee #2 and Brookings County – Toronto are not included. The two 115 kV lines were designed to provide access to the high voltage bulk transmission system of 230 kV and 345 kV lines. In transportation terminology, the higher voltage lines are the freeway and the lower voltage lines are the on-ramps to the freeway. (See response to DOC00022). The Brookings County – Yankee 115 kV #2 transmission line is not included because it is being constructed as part of the Buffalo Ridge Incremental Generation Outlet project that was approved in Docket No. E-002/CN-06-154, Order Granting

[1] The Southwestern Minnesota Study identified the Minnesota Valley – Panther – McLeod 230 kV line segment as being in need of reconductoring. To provide additional generation outlet capability, the entire circuit, which stretches from Minnesota Valley to Blue Lake Substation must be rebuilt.

Certificates of Need (Sept. 14, 2007). A route application was filed for this line on January 18, 2008. The Brookings County – Toronto 115 kV line was removed because it is not needed to achieve the 1,800 to 1,900 MW outlet capability. Rather, it would provide support to generation placed at Toronto Substation. If additional generation develops on the north end of the Ridge, then this line may be constructed as part of a specific generation project through its interconnection study.

- The Minnesota Valley – Panther – McLeod 230 kV reconductoring project was removed because rebuilding or replacement of the Minnesota Valley – Blue Lake 230 kV line is the next step in developing further outlet capacity. Additionally, further analyses have determined that identified outlet capacity level can be achieved for the Buffalo Ridge Area without reconductoring the line based on upgrades that have taken place. We note that the potential effect of the construction of the Minnesota Valley – Blue Lake 230 kV project on the outlet capability of the system is currently unclear. If the anticipated double circuited 345 kV structures are placed in the same right-of-way as the existing line, the existing line would have to be taken out of service, thereby reducing the outlet capability of the system. This work could not begin until the Twin Cities – Brookings County 345 kV Project is in service because, as noted in the Southwestern Minnesota Study, "outage of this line causes severe reductions in permissible SW Minnesota generation outlet." (Application Appendix A-4, p. 37.) If the 345 kV structures were placed parallel to the existing line, the Minnesota Valley – Blue Lake 230 kV line might be able to operate during the construction period and construction could potentially begin prior to the in-service date of the Twin Cities – Brookings County 345 kV Project.

Exhibit 1 contains further discussion of more minor modifications of the list contained in the Southwestern Minnesota Study.

The list of facilities for the Twin Cities – Brookings County 345 kV Project will likely be further refined to coordinate with the generation outlet studies currently underway and the recommended facilities that result from those studies. Significantly, preliminary analyses have concluded that the connection between the Minnesota Valley Substation and a new Hazel Creek Substation should be upgraded from 230 kV to either single circuit or double circuit 345 kV in light of the anticipated Minnesota Valley – Blue Lake 230 kV project. 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. Applicants will provide all parties with additional information as it becomes available.

Response By:	Jared Alholinna
Title:	Senior Transmission Planning Engineer
Department:	Transmission Planning, Contracts & Strategy
Company:	Great River Energy
Telephone:	763-241-5797
Date:	March 19, 2008

EXHIBIT 1

LIST OF TWIN CITIES – BROOKINGS COUNTY 345 kV PROJECT FACILITIES

High Voltage Transmission Lines

Brookings County – Lyon County 345 kV transmission line
Lyon County – Hazel 345 kV transmission line
Lyon County – Franklin – Helena 345 kV, double circuit transmission line
Hazel Creek – Minnesota Valley – 230 kV transmission line
Helena – Lake Marion – Hampton Corners 345 kV transmission line

As noted in the main response, the two 115 kV projects suggested in the Southwestern Minnesota Study (Brookings County – Yankee #2 and Brookings County – Toronto) are not included.

Rebuilds/Reconductor

Lake Marion – Kenrick – Dakota Heights – Burnsville 115 kV (reconductor)
Minnesota Valley – Maynard – Kerkhoven Tap 115 kV (rebuild)
Helena – Blue Lake 345 kV (reconductor)
Grant County – Morris 115 kV (reconductor)
St. Cloud Tap – Wakefield 115 kV (reconductor)
Wilmarth – Eastwood 115 kV line (rebuild)

As noted in the main response, the Minnesota Valley – Panther – McLeod 230 kV reconductoring project is not included. In addition, as part of the Southwestern Minnesota Study, planning engineers identified the existing Canby – Burr Junction 115 kV line as needing to be rebuilt to ensure that the existing lower voltage circuits are not overloaded if one of the new high voltage transmission lines fails. The rebuild of the Canby – Burr Junction 115 kV line, however, is no longer appropriate because it was only required if the Toronto line were constructed.

The other change to the rebuild/reconductor list is that the Wilmarth – Eastwood 115 kV line is now listed as a rebuild. The Wilmarth – Eastwood line is currently limited by approximately 3.7 miles of 795 ACSR conductor. The rest of the line is constructed of 795 ACSS conductor. Eliminating the limitation on this line will require removing the existing 795 ACSR conductor and replacing it with 795 ACSS conductor (matching the rest of the line). Because of the design standards required to

support ACSS conductor, it is assumed this will require a rebuild of the limiting segment.

Transformers, Capacitors and Shunt Reactors

Transformers	MVA	
Brookings Co 345/115 kV transformer #2	1 x 448	
Lyon Co 345/115 kV transformer	1 x 448	
Lake Marion 345/115 kV transformer	1 x 448	
Hazel 345/230 kV transformer	2 x 336	
Eden Prairie #10 transformer replacement	448→672	(alternative: add 345 kV line breaker)
Franklin 115/69 kV transformer replacement	2 x 47→2 x 70	
Morris 230/115 kV #2	100→150	
Willmar 115/69 #2	112	
Total Increase	2,448	

Reactive (voltage control) facilities	
Shunt Capacitors	MVAR
Brookings Co 115 kV	2 x 40
Lyon Co 115 kV	2 x 30→3 x 40
Lk Yankton 115 kV	4 x 20→4 x 40
Hazel 230 kV	3 x 60
Franklin 115 kV	4 x 30
McLeod 115 kV	4 x 30
Blue Lk 115 kV	1 x 80
Forbes 500 kV capacitor #3 (or equivalent)	1 x 300
Total Increase	1,020

Shunt Reactors	MVAR
Brookings Co	1 x 50
Lyon Co	1 x 50
Hazel	1 x 50
Franklin	2 x 50
Lk Marion	1 x 50
Total	300

The transformers that are part of the Twin Cities – Brookings County 345 kV Project are the same as those identified in the Southwestern Minnesota Study. (See Application Appendix A-4, p. 39.) These new units are located along major transmission corridors for wind outlet and, thus, are needed regardless of the assumptions made regarding locations of new generation.

The capacitors and shunt reactors that are part of the Twin Cities – Brookings County 345 kV Project are also the same as those identified in the Southwestern Minnesota Study which presumed certain general generation locations. (See Application Appendix A-4, pp. 39-40.) The precise size and locations of these facilities, however, will be finalized based on the ultimate locations of new generators that connect to the electrical system and the results of their respective interconnection studies. The specific types of wind generators that connect to the system will also affect these sizes and locations, particularly the sizes and locations of the shunt reactors. As shunt reactors and capacitors do not require the lead-time required of transformers and transmission lines, it makes sense to postpone determination of their precise locations until it can be more accurately determined which installations will result in the most efficient system support.

Substations New

Helena 345 kV Switching Station near Jordan
Hampton Corner 345 kV Switching Station

The Southwestern Minnesota Study also recommends a new Hazel Creek Substation. This substation is being constructed as part of the Buffalo Ridge Incremental Generation Outlet project and will be permitted separately.

Substations Modified

Substations-modified

Lyon Co	add 345 yard, 345/115 kV transformer, 115 kV capacitors & breakers, shunt reactor
Franklin	add 345 yard, 345/115 kV transformer, 115 kV capacitors & breakers, shunt reactors; Replace 115/69 kV transformers
Lk Marion	add 345 yard, 345/115 kV transformer, 115 kV capacitors & breakers, shunt reactor
Lk Yankton	upgrade 115 kV shunt capacitors to 4 x 40 MVAR
Blue Lake	add 115 kV shunt capacitor
Minn Valley	add 230 kV ring bus

The Southwestern Minnesota Study identified four other substations requiring modifications. (See Application Appendix A-4, p. 40.) The modifications to the Forbes 500 kV Substation are already being been done as part of the Forbes Bus Reconfiguration. The modifications to the Yankee Substation and the Brookings County Substation are being completed as part of the Buffalo Ridge Incremental

Generation Outlet project. The modifications to the Toronto Substation are not required because the Brookings County – Toronto line is no longer being constructed.

2129954v5

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002/RP-07-1572
Response To: Izaak Walton League Information Request No. 4
Date Received: March 4, 2008

Question:

Please provide any updated information in Xcel's possession regarding the planning reserve margin adjustments discussed in the 2008 Resource Plan on pages 4-19 to 4-22. This is a continuing request

Response:

On February 5, 2008 the Midwest PRSG posted the attached preliminary report on reserve sharing to the MISO website. As noted in the report, the PRSG adopted a planning reserve margin of 14.2% for Xcel Energy. This is the reserve margin that we would be required to maintain over our 50% forecast of uninterrupted load in order to be in compliance with the proposed Midwest PRSG standard.

At this time, the PRSG is still considering the criteria to be used to determine the generation ratings of each generation facility used to calculate accredited capacity toward meeting our load and planning reserves. Once this is established, we will update our analysis and plan to the extent necessary.

Response By: Betsy Engelking
Title: Manager
Department: Resource Planning and Bidding
Telephone: 612-330-7987
Date: 03-14-08

Midwest PRSG

Reliability through Collaboration

February 5th, 2008

Preliminary Report of the Midwest Planning Reserve Sharing Group (Midwest PRSG)

The Midwest PRSG is a voluntary group of load serving entities that has been established to study the collective resources of the group and determine a minimum level of planning reserve requirements based upon reliability principles and standards set forth by applicable Reliability Entities. The information provided below represents a preliminary report of the minimum reserve margins that the group is committing to for the planning year June 2008 –May 2009. The Midwest PRSG is providing this report for informational purposes and will publish a full report within the next couple of months. The full report will contain the information necessary to properly interpret the reserve margin targets established by the Midwest PRSG.

Recognizing that the availability of planning reserves is necessary to maintain resource adequacy, the Midwest PRSG performed several Loss of Load Expectation (LOLE) analyses to determine reserve margins consistent with Regional Entity standards. The LOLE analyses included several sensitivity studies to input variables such as load forecast uncertainty, forced outage rates, and zonal vs. Midwest PRSG-wide resource adequacy targets.

The Midwest PRSG has approved the following planning reserve margin targets for the 2008 – 2009 planning year for four zones within the Midwest PRSG. The Midwest PRSG approval was based on its review of numerous LOLE analyses and represents the group's consensus of the reserve margins necessary to maintain a resource adequacy criterion of 1 day in 10 years LOLE.

Midwest PRSG Planning Reserve Margins	
East	13.7 %
Central	14.3 %
West	14.2 %
Manitoba Hydro	7.7 %

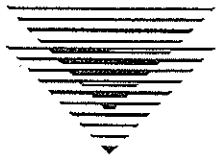
The membership of each Midwest PRSG zone is attached for reference.

Please direct questions to the Midwest PRSG leadership or Group Administrator.

David Sonntag
Chair MPRSG
sonntagd@dteenergy.com

Chris Plante
Vice-Chair MPRSG
CTPlante@wisconsinpublicservice.com

Jesse Moser
Group Administrator
jmoser@midwestiso.org



Midwest PRSG

Reliability through Collaboration

PRSG Participant	Zone
Ameren Services	Central
Duke Energy	Central
Hoosier Energy Rural Electric Coop, Inc.	Central
Illinois Municipal Electric Agency	Central
Indianapolis Power & Light Co.	Central
Northern Indiana Public Service Co.	Central
Southern Indiana Gas & Electric Company, Inc.	Central
Wabash Valley Power Association, Inc.	Central
City of Lebanon, Ohio	East
Consumers Energy Co.	East
Detroit Edison Co.	East
First Energy	East
Lansing Board of Water & Light	East
Michigan Public Power Agency	East
Wolverine Power Supply Coop, Inc.	East
Manitoba Hydro	Manitoba Hydro
Alliant Energy	West
Basin Electric Power Cooperative	West
Central Iowa Power Cooperative	West
Great River Energy	West
Madison Gas & Electric Co.	West
MidAmerican Energy Co.	West
Minnesota Power, Inc.	West
Montana Dakota Utilities Co.	West
NorthWestern Energy	West
Otter Tail Power Co.	West
Southern Minnesota Municipal Power Agency	West
We Energies	West
Western Area Power Administration	West
Wisconsin Public Power, Inc.	West
Wisconsin Public Service Corp.	West
Xcel Energy	West

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: George Crocker NAWO/ILSR
Information Request No. 5
Date Received: February 13, 2008

Question:

The Bonneville Power Administration is using aluminum shunts, which are strands of aluminum added to a transmission line that provides another path for current to travel through to relieve strain on key line components, to allow transmission lines to carry more electricity capacity while also meeting more stringent outage standards. BPA said it was able to increase the amperage on one of its major 230-kV lines at far less cost than rebuilding and replacing existing equipment. [More information at http://www.piersystem.com/go/doc/1582/186166/]

Have the CAPX2020 utilities investigated using aluminum shunts as an alternative to replace or delay the need for the proposed CAPX2020 lines? Describe the outcome of the investigation in relation to each of the three lines and each of the three claimed categories of need.

If not, can the applicants please explain why this alternative is not viable for consideration to meet the claimed needs? If this alternative is viable describe the expected value of this technology in relation to each of the three 345-kV lines and each of the three claimed categories of need.

Response:

When conductors are spliced together along a transmission line, compression connectors are used. In some cases, the MVA capacity of the compression connectors is lower than the MVA capacity of the line. As a result, the capacity of such a line is limited by the capacity of the splice.

Aluminum shunts are used to increase the capacity of the spliced areas, which allows the line to reach its full MVA capacity. As applied here, shunts are aluminum wires that attach to the conductor and stretch across the compression connector, essentially creating a bypass where additional current can flow on the line. When aluminum

shunts are used, poles often need to be raised or rebuilt to increase ground clearance. The higher flows and increased conductor temperatures that result from allowing more current through the line will cause the line to sag more than its initial design allows.

Generally speaking, 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.

In addition, even if the capacity of a particular line were limited by the capacity of a compression connector, aluminum shunt installations would not eliminate the need for the proposed facilities.

In the case of the Twin Cities – Fargo 345 kV line, the need drivers in two of the benefit areas (southern Red River Valley and Alexandria area) are voltage-based and not related to the current-carrying capacity of transmission lines in the area. Because the critical contingencies in these areas result in low voltage, a solution such as this one that does not result in lower impedance (and, thus, more efficient delivery of power) to an area will not postpone the need for additional support in those areas. Additionally, in the St. Cloud area, the critical contingency is the loss of the Benton County – Granite City 115 kV double-circuit line. When this contingency occurs, the power for the area is forced to be delivered via the Monticello – St. Cloud 115 kV line. This line was rebuilt within the last five years. Because it is such new construction, it would have been designed such that its thermal capacity would be limited by the capacity of the wire and not any of the hardware used to support it. As such, bypassing the compression connectors on this line would not result in any increase in its capacity.

A primary focus of the Twin Cities – Brookings County 345 kV Project is generation outlet capacity. As generation is added in southwest Minnesota, there are more thermal limits that are observed, but these thermal limits are generally the limits of the conductors, not the limits of the compression connectors. For example, one of the greatest limiters to increasing outlet capacity is the Minnesota Valley – Blue Lake 230 kV line. This line becomes overloaded when certain generation levels are reached. The capacity of this line is not, however, limited by its compression connectors. The conductor is capable of being operated at the full rating of its conductor, meaning that installing shunts on its compression connectors would not yield any increase in the capacity of the line.

The need for the Twin Cities – La Crosse 345 kV Project is driven primarily by the growing community power demands needed for regional electrical system support, as well as strengthening the reliability of the Southeast portion of Minnesota with another strong 345 kV source. Similarly to the Fargo discussion above, the lines which are forced to deliver the power under contingency situations for Rochester and La Crosse are designed such that its thermal capacity would be limited by the capacity of the wire and not any of the hardware used to support it. As such, bypassing the compression connectors on this line would not result in any increase in its capacity.

Response By:	Daniel Kline
Title:	Transmission Planning Engineer
Department:	Transmission Reliability and Assessment
Company:	Xcel Energy
Telephone:	612-330-7547
Date:	March 10, 2008

Response By:	Amanda King
Title:	Sr. Transmission Planning Engineer
Department:	Transmission Planning
Company:	Xcel Energy
Telephone:	612-330-5931
Date:	March 10, 2008

Response By:	Jared Alholinna
Title:	Senior Transmission Planning Engineer
Department:	Transmission Planning, Contracts & Strategy
Company:	Great River Energy
Telephone:	763-241-5797
Date:	March 10, 2008

2144728v1

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: George Crocker NAWO/ILSR
Information Request No. 6
Date Received: February 13, 2008

Question:

Recently 3M has developed an Aluminum Conductor Composite Reinforced (ACCR) wire for use in transmission applications. See: http://solutions.3m.com/wps/portal/3M/en_US/EMD_ACCR/ACCR_Home/

Have the CAPX2020 utilities investigated using this ACCR wire as an alternative to replace or delay the need for the proposed CAPX2020 lines? Describe the outcome of the investigation in relation to each of the three lines and each of the three claimed categories of need.

If not, can the applicants please explain why this alternative is not viable for consideration to meet the claimed needs? If this alternative is viable describe the expected value of this technology in relation to each of the three 345 kV lines and each of the three claimed categories of need.

Response:

The predominant types of conductor used on the regional transmission system are Aluminum Core Steel Reinforced ("ACSR") and Aluminum Steel Supported ("ACSS"). There are, however, some instances where the 3M, ACCR conductor is being used (*e.g.*, Black Dog – Blue Lake 115 kV line).

The capacity of the ACCR conductor is greater than the capacity of the ACSR and ACSS conductors, however, the impedance characteristics of all three types of conductor are similar. On average, the ACCR conductor costs approximately four to eight times more than the ACSS conductor that is proposed for the three 345 kV Projects.

Reconductoring, using the ACCR conductor or any other type of conductor, is an improvement that can address overloads on individual lines. Typically by installing new conductors, the capacity of a line can be increased 20 to 50 percent. Planning

engineers have concluded that reconductoring is not a means for addressing the generation outlet capability and increased local and regional reliability needs identified in the Application.

In the case of the Twin Cities – Fargo 345 kV line, the reliability of the electrical system in the southern Red River Valley and Alexandria areas is compromised due to low voltage during certain critical contingencies. To improve voltages, additional power flow capability (*i.e.*, lower impedance on the existing ACSR and ACSS transmission lines) is needed. Replacing existing conductors with ACCR could improve individual line performance, but would not reduce the impedance of the transmission system in the area. As a result, there would be no increase in the system's injection capability and no improvement to low voltages would be recognized. To reduce the impedance of the transmission system serving the south Red River Valley and Alexandria areas, additional high voltage transmission facilities must be constructed.

Similarly, with respect to the Twin Cities – Brookings County 345 kV Project, reconductoring is not a viable option. As noted in the Application, the reconductoring strategy for improving outlet capability was largely exhausted with the Buffalo Ridge Incremental Generation Outlet ("BRIGO") study development. Application, Section 5.3. As more generation is added to the system in southwest Minnesota, there are more thermal (overload) limits on the existing transmission grid that are observed. The ACCR conductor could be utilized to relieve the overloading on a particular line or a series of lines but would not improve the overall capability of the system. Lower grid impedances are necessary to accommodate the transmission of large amounts of power over long distances. To improve the power flows, additional transmission facilities are needed.

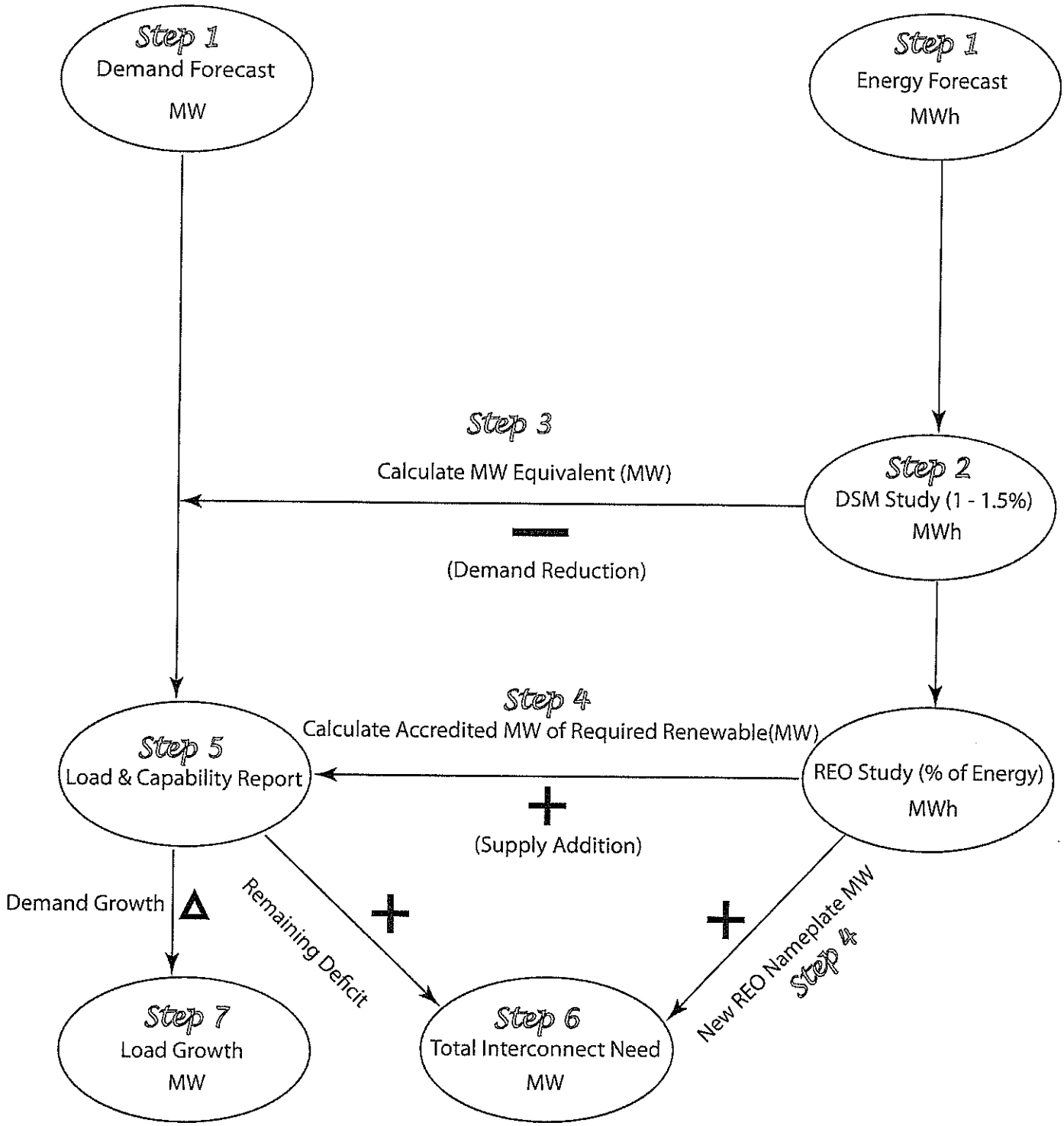
Similarly, with respect to the Twin Cities – La Crosse 345 kV Project, reconductoring is not a viable option. As discussed in the Application, the system in La Crosse is beginning to experience low system voltages, only correctable by running expensive generation in advance of any contingencies. To improve voltages, additional power flow capability additional high voltage transmission facilities must be constructed. Replacing existing conductors with ACRR could improve individual line performance, but would not reduce the impedance and therefore no improvement to low voltages would be recognized. To reduce the impedance on existing transmission lines, additional high voltage transmission facilities must be constructed bringing a new 345 kV source to both the Rochester and La Crosse areas.

Response By:	Daniel Kline
Title:	Transmission Planning Engineer
Department:	Transmission Reliability and Assessment
Company:	Xcel Energy
Telephone:	612-330-7547
Date:	March 10, 2008

Response By:	Amanda King
Title:	Sr. Transmission Planning Engineer
Department:	Transmission Planning
Company:	Xcel Energy
Telephone:	612-330-5931
Date:	March 10, 2008

Response By:	Jared Alholinna
Title:	Senior Transmission Planning Engineer
Department:	Transmission Planning, Contracts & Strategy
Company:	Great River Energy
Telephone:	763-241-5797
Date:	March 10, 2008

2144729v1



System Forecast

CERTIFICATE OF NEED CRITERIA

I. NEED ANALYSIS—Hwikwon Ham, Christopher Shaw, Susan Peirce

Part 1—Forecast and Load & Capability Analysis—Hwikwon Ham, Christopher Shaw

7849.0120 A. the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states, considering:

7849.0120 A (1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;

7849.0120 C (1) the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs;

Part 2—Reliability Analysis—Hwikwon Ham

216B.243 Subd. 3. "(9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

Part 3—REO Compliance—Susan Peirce

Subpart A

216B.243 Subd. 3. (10) "whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691"

> 216B.1691 Subd. 2. Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail consumers, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies; and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies.
>
> Subd. 2a. (a) Except as provided in paragraph (b), each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated:
>
> (1) 2012 12 percent

(2) 2016 17 percent
(3) 2020 20 percent
(4) 2025 25 percent.

(b) An electric utility that owned a nuclear generating facility as of January 1, 2007, must meet the requirements of this paragraph rather than paragraph (a). An electric utility subject to this paragraph must generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota or the retail customer of a distribution utility to which the electric utility provides wholesale electric service so that at least the following percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated:

(1) 2010 15 percent
(2) 2012 18 percent
(3) 2016 25 percent
(4) 2020 30 percent.

Of the 30 percent in 2020, at least 25 percent must be generated by wind energy conversion systems and the remaining five percent by other eligible energy technology.

Subpart B

216B.1612 Subd. 5 (c) The commission shall consider the efforts and activities of a utility to purchase energy from C-BED projects when evaluating its good faith effort towards meeting the renewable energy objective under section 216B.1691.

II. PREFERENCE TESTS—Steve Rakow, Christopher Davis

Part 1—Renewable Preference—Steve Rakow

216B.243 Subd. 3a. " 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."

216B.2422 Subd. 4. "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."

Part 2—DSM Preference—Christopher Davis

216B.243, subd. 3. "No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures"

216B.243 Subd. 3. "(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically"

7849.0120 A (2) the effects of the applicant's existing or expected conservation programs and state and federal conservation programs;

III. ALTERNATIVE ANALYSIS—Steve Rakow

Part 1—Screening Analysis—Steve Rakow

7849.0120 B (1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;

Part 2—Cost Analysis—Steve Rakow

7849.0120 B. a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering:

7849.0120 A (4) the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand; and

7849.0120 B (2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;

7849.0120 B (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and

Part 3—DG Analysis—Steve Rakow

216B.2426 "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."

> 216B.169 Renewable and high-efficiency energy rate options. Subdivision 1. Definitions. For the purposes of this section, the following terms have the meanings given them…

(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.

Part 4—Comparison of Reliability of Alternatives—No Direct Testimony

7849.0120 B (4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;

IV. SOCIO-ECONOMIC ANALYSIS——Environmental Report

7849.0120 C. by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health, considering:

7849.0120 A (5) the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources;

7849.0120 C (2) the effects of the proposed facility, or a suitable modification thereof, upon the natural and socioeconomic environments compared to the effects of not building the facility;

7849.0120 C (3) the effects of the proposed facility, or a suitable modification thereof, in inducing future development; and

7849.0120 C (4) the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality; and

V. POLICY ANALYSIS—Steve Rakow

Part 1—Policy Analysis—Steve Rakow

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

7849.0120 A (3) the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974;

Part 2—Transmission Planning Compliance—Steve Rakow

216B.243 Subd. 3. (10) "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;"

216B.2425 Subd. 7. "Transmission needed to support renewable resources.

(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.

(b) Transmission projects determined by the commission to be necessary to support a utility's plan under section 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."

NOTE: Subdivision 7, paragraph (b), as added by Laws 2005, chapter 97, article 2, section 3, expires January 1, 2010. Laws 2005, chapter 97, article 2, section 7.

Part 3—Environmental Cost Planning—Steve Rakow

216B.243 Subd. 3. (12) "if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk."

Part 4—Mesaba Preference—Steve Rakow

216B.1694 Subd. 2. "(a) An innovative energy project:

(5) shall, prior to the approval by the commission of any arrangement to build or expand a fossil-fuel-fired generation facility, 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"

Year	% of 2005 CO2 level	Xcel-System Emissions Goal	Sherco Estimate / System Goal
2005	100.0%	28,190,200	44%
2006	98.5%	27,767,347	45%
2007	97.0%	27,344,494	46%
2008	95.5%	26,921,641	46%
2009	94.0%	26,498,788	47%
2010	92.5%	26,075,935	48%
2011	91.0%	25,653,082	49%
2012	89.5%	25,230,229	49%
2013	88.0%	24,807,376	50%
2014	86.5%	24,384,523	51%
2015	**85.0%**	23,961,670	52%
2016	84.0%	23,679,768	53%
2017	83.0%	23,397,866	53%
2018	82.0%	23,115,964	54%
2019	81.0%	22,834,062	55%
2020	80.0%	22,552,160	55%
2021	79.0%	22,270,258	56%
2022	78.0%	21,988,356	57%
2023	77.0%	21,706,454	57%
2024	76.0%	21,424,552	58%
2025	75.0%	21,142,650	59%
2026	74.0%	20,860,748	60%
2027	73.0%	20,578,846	61%
2028	72.0%	20,296,944	61%
2029	71.0%	20,015,042	62%
2030	**70.0%**	19,733,140	63%
2031	67.5%	19,028,385	65%
2032	65.0%	18,323,630	68%
2033	62.5%	17,618,875	71%
2034	60.0%	16,914,120	74%
2035	57.5%	16,209,365	77%
2036	55.0%	15,504,610	80%
2037	52.5%	14,799,855	84%
2038	50.0%	14,095,100	88%
2039	47.5%	13,390,345	93%
2040	45.0%	12,685,590	98%
2041	42.5%	11,980,835	104%
2042	40.0%	11,276,080	110%
2043	37.5%	10,571,325	118%

2044	35.0%	9,866,570	126%
2045	32.5%	9,161,815	136%
2046	30.0%	8,457,060	147%
2047	27.5%	7,752,305	161%
2048	25.0%	7,047,550	177%
2049	22.5%	6,342,795	196%
2050	**20.0%**	5,638,040	221%

Notes:

1. Percentages from Minn. Stat. 216H.02 (2007)

2. Percentages in bold are mentioned in statute.

3. Statute has years reduced from 2005 level.

4. Xcel System CO2 from Reply to IR 10 in Docket No. E002/RP-07-1572.

5. Estimated Sherco 2005 CO2 output: *12,454,883*

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis MN 55401-2138

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

LeRoy Koppendrayer	Chair
Marshall Johnson	Commissioner
Kenneth Nickolai	Commissioner
Phyllis Reha	Commissioner
Thomas Pugh	Commissioner

IN THE MATTER OF THE APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR CERTIFICATE OF NEED FOR TRANSMISSION LINES IN WESTERN MINNESOTA	Docket No. E017 et al/CN-05-619

DIRECT TESTIMONY OF STEPHEN RAKOW

ON BEHALF

OF THE MINNESOTA DEPARTMENT OF COMMERCE

NOVEMBER 17, 2006

Fourth, I determined the externality costs associated with each alternative. The externality costs are derived from the energy losses. That is, because energy is lost during transmission from BS2 and other power plants, the grid must produce additional energy and burn extra fuel in the process. Again, the energy losses are pro-rated among the Applicants and valued based upon multiplying the emissions per MWh (data from the Minnesota Office of Environmental Assistance at www.moea.state.mn.us/lc/ippat/ReductionCalculator.zip) by the Commission's externality values. Then the present values of the externality costs are determined for each Applicant and the present values are summed across the Applicants for each alternative. The result is the present value of the externality cost for each alternative. When the externality costs are added to the financial costs (from the first three steps) the result is the societal cost of the alternatives.

I note that all calculations are shown in DOC Exhibit No. ___ (SRR-4).

Q. I see in DOC Exhibit No. ___ (SRR-4) that you used two different discount rates, one labeled 'nominal' and one labeled 'real'; why is that?

A. In essence, the treatment given inflation in the data being discounted determines whether a real or nominal discount rate should be used. Real discount rates exclude inflation as a consideration. Therefore, if the data being discounted is expressed in terms that do not consider inflation (real dollars), then a real discount rate is appropriate. Nominal discount rates include inflation as a consideration. Therefore, if the data being discounted is expressed in terms that include inflation (nominal dollars), then a nominal discount rate should be used.

Clearly the energy cost and the emission or externality cost values are in real dollars because they are single values that are assumed to be constant over the entire 35 year time horizon for the present value calculation. The Commission's externality cost values are subject to an annual inflation factor. Thus the single externality cost that I use is a real dollar figure and a real discount rate must be applied. Similarly, it would be unreasonable to assume that 2006 energy costs are not subject to inflation over the next 35 years. Therefore, the single energy cost that I use must also be considered as a real dollar figure and a real discount rate again must be applied.

The consideration of inflation inherent in the capital or investment cost and the demand-loss cost calculations is not as clear. The cost of the demand losses, while expressed as a single number, is based upon the calculation of the fixed charge rate for generation facilities. The investment cost, also expressed as a single number, is based upon the calculation of the fixed charge rate for transmission facilities. Fixed charge rates usually are calculated on a nominal dollar basis. That is, in step one the specific cost flows each year are determined and a present value is determined. Then in step two the LARR is calculated. The LARR represents a constant, nominal dollar stream whose present value equals the present value of the actual dollar cost stream from step one. Therefore, the investment cost and the cost of the demand losses are based upon nominal dollars and a nominal discount rate is appropriate.

Q. Please explain how you calculated the capital cost of the alternatives.

A. The starting point is the point estimate of the capital cost (in 2006 dollars) provided in the *Supplemental Direct Testimony of Dean Pawlowski* (Pawlowski Supplemental) at page

Utility	Public Power ??	Share of Twin Cities--La Crosse	Share of Twin Cities--Fargo	Share of Twin Cities--Brookings
CMMPA	Y	0.0%	0.0%	2.2%
Dairyland	Y	11.0%	0.0%	0.0%
Great River	Y	0.0%	25.0%	16.5%
Minn Power	N	0.0%	14.7%	0.0%
Missouri River	Y	0.0%	11.0%	5.1%
Otter Tail	N	0.0%	13.2%	4.1%
Rochester	Y	9.0%	0.0%	0.0%
SMMPA	Y	13.0%	0.0%	0.0%
WPPI	Y	3.0%	0.0%	0.0%
Xcel	N	64.0%	36.1%	72.1%
Public Power Share		36.0%	36.0%	23.8%
Investor Owned Share		64.0%	64.0%	76.2%
Mid-point Project Cost		$ 345.0	$ 475.0	$ 632.5
Public Power-Share of Total			30.7%	
Investor Owned-Share of Total			69.3%	

Item	Public Power	Investor Owned	Total Project
Total Project Share	30.7%	69.3%	
Transmission Fixed Charge Rate	7.70%	12.75%	
Weighted Fixed Charge Rate	2.36%	8.84%	11.20%

Item	Public Power	Investor Owned	Total Project
Total Project Share	30.7%	69.3%	
Nominal Discount Rate	5.50%	7.60%	
Weighted Nominal Discount Rate	1.69%	5.27%	6.96%

Item	Public Power	Investor Owned	Total Project
Investment Cost (Million Dollars)	$ 1.000	$ 1.000	$ 1.000
Transmission Fixed Charge Rate	7.70%	12.75%	11.20%
Annual Revenue Requirement per Million Dollars	$ 0.077	$ 0.128	$ 0.112

Item	Public Power	Investor Owned	Total Project
Transmission Life	35	35	35
Annual Revenue Requirement per Million Dollars	$ 0.077	$ 0.128	$ 0.112
Nominal Discount Rate	5.50%	7.60%	7.00%
Present Value per Million Dollars Investment Cost	$ 1.19	$ 1.55	$ 1.45

Utility	Public Power ??	Share of Twin Cities--La Crosse	Share of Twin Cities--Fargo	Share of Twin Cities--Brookings
CMMPA	Y	0.0%	0.0%	2.2%
Dairyland	Y	11.0%	0.0%	0.0%
Great River	Y	0.0%	25.0%	16.5%
Minn Power	N	0.0%	14.7%	0.0%
Missouri River	Y	0.0%	11.0%	5.1%
Otter Tail	N	0.0%	13.2%	4.1%
Rochester	Y	9.0%	0.0%	0.0%
SMMPA	Y	13.0%	0.0%	0.0%
WPPI	Y	3.0%	0.0%	0.0%
Xcel	N	64.0%	36.1%	72.1%
Public Power Share		36.0%	36.0%	23.8%
Investor Owned Share		64.0%	64.0%	76.2%
Mid-point Project Cost		$ 345.0	$ 475.0	$ 632.5
Public Power-Share of Total		30.7%		
Investor Owned-Share of Total		69.3%		

Item	Public Power	Investor Owned	Total Project
Total Project Share	30.7%	69.3%	
Generation Fixed Charge Rate	7.7%	12.5%	
Weighted Fixed Charge Rate	2.36%	8.66%	11.0%

Item	Public Power	Investor Owned	Total Project
Cost per MW lost (million $)	$ 1.035	$ 1.035	$ 1.035
Generation Fixed Charge Rate	7.7%	12.5%	11.0%
Annual Revenue Requirement per MW lost (million $)	$ 0.080	$ 0.129	$ 0.114

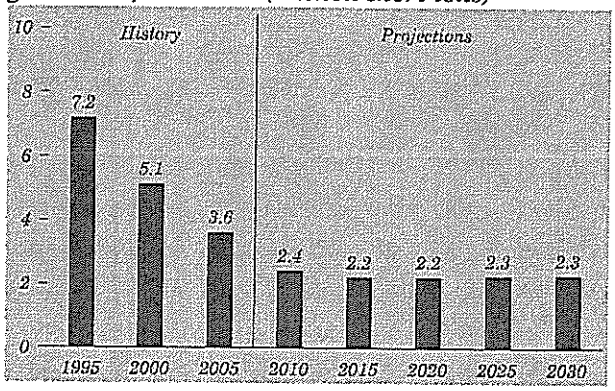
Utility	Public Power ??	Share of Twin Cities--La Crosse	Share of Twin Cities--Fargo	Share of Twin Cities--Brookings
CMMPA	Y	0.0%	0.0%	2.2%
Dairyland	Y	11.0%	0.0%	0.0%
Great River	Y	0.0%	25.0%	16.5%
Minn Power	N	0.0%	14.7%	0.0%
Missouri River	Y	0.0%	11.0%	5.1%
Otter Tail	N	0.0%	13.2%	4.1%
Rochester	Y	9.0%	0.0%	0.0%
SMMPA	Y	13.0%	0.0%	0.0%
WPPI	Y	3.0%	0.0%	0.0%
Xcel	N	64.0%	36.1%	72.1%
Public Power Share		36.0%	36.0%	23.8%
Investor Owned Share		64.0%	64.0%	76.2%
Mid-point Project Cost		$ 345.0	$ 475.0	$ 632.5
Public Power-Share of Total			30.7%	
Investor Owned-Share of Total			69.3%	

Item	Public Power	Investor Owned	Total Project
Total Project Share	30.7%	69.3%	
Nominal Discount Rate	5.5%	7.6%	
Weighted Nominal Discount Rate	1.69%	5.27%	7.0%

Item	Public Power	Investor Owned	Total Project
Transmission Life	35	35	35
Annual Revenue Requirement per MW lost (million $)	$ 0.080	$ 0.129	$ 0.114
Nominal Discount Rate	5.5%	7.6%	7.0%
Present Value per MW lost (million $)	$ 1.23	$ 1.57	$ 1.48

Nitrogen Oxide Emissions Also Fall As CAIR Takes Effect

Figure 95. Nitrogen oxide emissions from electricity generation, 1995-2030 (million short tons)



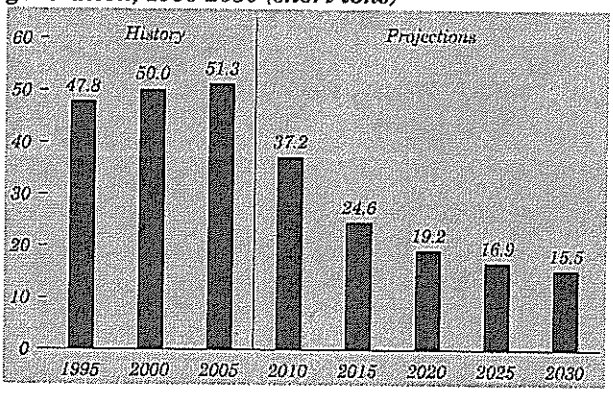
CAIR also mandates NO_x emission reductions in 28 States and the District of Columbia [*172*]. The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. As with the CAIR-mandated SO_2 reductions, each State can determine a preferred method for reducing NO_x emissions. Options include joining the EPA's cap and trade program and enforcing individual State regulations. Each State will be subject to two NO_x limits: a 5-month summer season limit and an annual limit.

In the reference case, national NO_x emissions from the electric power sector are projected to fall from 3.6 million short tons in 2005 to 2.3 million short tons in 2030 (Figure 95). Because the CAIR caps are inflexible, different assumptions in the high and low growth and high and low fuel price cases do not affect the projections for aggregate NO_x emissions.

Between 2009 and 2030, after mandatory compliance begins, NO_x allowance prices are projected to range from $2,400 to $3,300 per ton emitted in the reference case, tending to rise as the emission caps tighten. By 2030, selective catalytic reduction equipment is projected to be added to an additional 116 gigawatts of coal-fired generating capacity. In the high price case, with more CTL capacity built, allowances are projected to be less costly, because CTL plants emit less NO_x than the coal-fired power plants they would displace. In the high economic growth case, with more coal-fired capacity in operation, allowance prices are projected to be slightly higher than in the reference case, even with the requirement for NO_x emission controls on all new plants.

Clean Air Mercury Rule Reduces Mercury Emissions

Figure 96. Mercury emissions from electricity generation, 1995-2030 (short tons)



EPA's CAMR, also promulgated in 2005, imposes a national cap on emissions of mercury, to be implemented in two phases [*173*]. As with CAIR, States can enact their own programs or participate in the EPA cap and trade system. Although no States have made final decisions, more stringent regulations have been proposed by several States in the East where many power plants use coal with higher mercury content.

AEO2007 assumes that all States will participate in the cap and trade program and meet the CAMR restrictions, with no mandates for further reductions. In the reference case, national mercury emissions are projected to be reduced by 70 percent, from 51.3 short tons in 2005 to 15.5 short tons in 2030 (Figure 96). Nationally, power producers are projected to retrofit 133 gigawatts of coal-fired capacity with activated carbon injection technology. (Mercury controls also are expected to help the States to meet CAIR targets, because the retrofits reduce SO_2 and NO_x emissions as well.) The 2030 projection is slightly higher than the final EPA cap of 15 short tons, however, because allowances banked from earlier years could be used by some power plants. Allowance prices are expected to climb to a high of $68,000 per pound in 2030.

Overall trends in mercury allowance prices are not greatly affected by economic growth or fuel price assumptions. The *AEO2007* high growth case projects more coal-fired generation than the reference case, causing allowance prices to rise more rapidly than in the reference case. In the high price case, more efficient CTL facilities are built, leading to a 6-percent decrease in total annual mercury emissions in 2030 relative to the reference case projection.

Utility	Public Power ??	Share of Twin Cities--La Crosse	Share of Twin Cities--Fargo	Share of Twin Cities--Brookings
CMMPA	Y	0.0%	0.0%	2.2%
Dairyland	Y	11.0%	0.0%	0.0%
Great River	Y	0.0%	25.0%	16.5%
Minn Power	N	0.0%	14.7%	0.0%
Missouri River	Y	0.0%	11.0%	5.1%
Otter Tail	N	0.0%	13.2%	4.1%
Rochester	Y	9.0%	0.0%	0.0%
SMMPA	Y	13.0%	0.0%	0.0%
WPPI	Y	3.0%	0.0%	0.0%
Xcel	N	64.0%	36.1%	72.1%
Public Power Share		36.0%	36.0%	23.8%
Investor Owned Share		64.0%	64.0%	76.2%
Mid-point Project Cost		$ 345.0	$ 475.0	$ 632.5
Public Power-Share of Total			30.7%	
Investor Owned-Share of Total			69.3%	

Item	Public Power	Investor Owned	Total Project
Total Project Share	30.7%	69.3%	
Real Discount Rate	2.5%	4.6%	
Weighted Real Discount Rate	0.77%	3.19%	4.0%

Item	Public Power	Investor Owned	Total Project
Transmission Life	35	35	35
Annual Energy Cost per MW lost (Low End)	$ 0.158	$ 0.158	$ 0.158
Real Discount Rate	2.5%	4.6%	4.0%
Present Value per MW lost (million $)	$ 3.66	$ 2.72	$ 2.95

Item	Public Power	Investor Owned	Total Project
Transmission Life	35	35	35
Annual Energy Cost per MW lost (High End)	$ 0.215	$ 0.215	$ 0.215
Real Discount Rate	2.5%	4.6%	4.0%
Present Value per MW lost (million $)	$ 4.98	$ 3.71	$ 4.01

Utility	Public Power ??	Share of Twin Cities--La Crosse	Share of Twin Cities--Fargo	Share of Twin Cities--Brookings
CMMPA	Y	0.0%	0.0%	2.2%
Dairyland	Y	11.0%	0.0%	0.0%
Great River	Y	0.0%	25.0%	16.5%
Minn Power	N	0.0%	14.7%	0.0%
Missouri River	Y	0.0%	11.0%	5.1%
Otter Tail	N	0.0%	13.2%	4.1%
Rochester	Y	9.0%	0.0%	0.0%
SMMPA	Y	13.0%	0.0%	0.0%
WPPI	Y	3.0%	0.0%	0.0%
Xcel	N	64.0%	36.1%	72.1%
Public Power Share		36.0%	36.0%	23.8%
Investor Owned Share		64.0%	64.0%	76.2%
Mid-point Project Cost		$ 345.0	$ 475.0	$ 632.5
Public Power-Share of Total			30.7%	
Investor Owned-Share of Total			69.3%	

Item	Public Power	Investor Owned	Total Project
Total Project Share	30.7%	69.3%	
Real Discount Rate	2.5%	4.6%	
Weighted Real Discount Rate	0.77%	3.19%	4.0%

Item	Public Power	Investor Owned	Total Project
Transmission Life	35	35	35
Annual O&M Cost per mile (Low End)	$ 300	$ 300	$ 300
Real Discount Rate	2.5%	4.6%	4.0%
Present Value per mile (dollars)	$ 6,900	$ 5,200	$ 5,600

Item	Public Power	Investor Owned	Total Project
Transmission Life	35	35	35
Annual O&M Cost per mile (High End)	$ 500	$ 500	$ 500
Real Discount Rate	2.5%	4.6%	4.0%
Present Value per mile (dollars)	$ 11,600	$ 8,600	$ 9,300

Project	Cost (million $ 2008) Low	High	Mileage	Source
Twin Cities--La Crosse	$ 338.25	$ 369.00	150	Figure 1-10, inflated at 2.5 %
Twin Cities--Fargo	$ 399.75	$ 574.00	250	Figure 1-10, inflated at 2.5 %
Twin Cities--Brookings County	$ 615.00	$ 681.63	200	Figure 1-10, inflated at 2.5 %
Associated Facilities	$ 71.75	$ 102.50		Page 1.17, inflated at 2.5%
Total	$1,424.75	$1,727.13	600	
On Peak Loss Benefit (MW)	234.20			Figure 5-10
Off Peak Loss Benefit (MW)	104.90			Figure 5-10

Item	Public Power	Investor Owned	Total Project	Source
Million Dollars Present Value per Million Dollars Spent [Investment Cost]	1.1851	1.5484	1.4501	Exhibit 7
Million Dollars Present Value per MW lost [Demand Cost]	1.2266	1.5712	1.4768	Exhibit 9
Million Dollars Present Value per MW lost [Low Energy Cost]	5.0456	3.7572	4.0689	Exhibit 11
Million Dollars Present Value per MW lost [High Energy Cost]	6.8741	5.1187	5.5434	Exhibit 11
Million Dollars Present Value per mile [Low O & M Cost]	0.0069	0.0052	0.0056	Exhibit 12
Million Dollars Present Value per mile [High O & M Cost]	0.0116	0.0086	0.0093	Exhibit 12
PVRR Capital Cost (Low)	$ 1,688.4	$ 2,206.1	$ 2,066.1	Line 7 (Low) * Line 13
PVRR Capital Cost (High)	$ 2,046.8	$ 2,674.3	$ 2,504.6	Line 7 (High) * Line 13
PVRR O&M Cost (Low)	$ 4.1	$ 3.1	$ 3.4	Line 7 (Miles) * Line 17
PVRR O&M Cost (High)	$ 7.0	$ 5.2	$ 5.6	Line 7 (Miles) * Line 18
PVRR Demand Benefit	$ 287.26	$ 367.98	$ 345.86	Line 9 * Line 14
PVRR Energy Benefit (Low)	$ 529.29	$ 394.13	$ 426.83	Line 10 * Line 15
PVRR Energy Benefit (High)	$ 721.09	$ 536.95	$ 581.50	Line 10 * Line 16
PVRR Net Total Cost (Low)	$ 876.03	$1,447.14	$1,296.76	Line 19 + Line 21 - Line 23 - Line 24
PVRR Net Total Cost (High)	$1,045.38	$1,774.56	$1,582.79	Line 20 + Line 22 - Line 23 - Line 26

Data-Applicant Reply to IR 40	Million $ (2008 $)			
	Total Cost	500 kV Incremental	Base Cost	Percent Increase
Applicants Response	$ 536.08	$ 136.33	$ 399.75	34%

	With Winnipeg to Fargo		Without Winnipeg to Fargo	
Build and Operate at 500 kV	**0 MW Transfer**	**1,250 MW Transfer**	**0 MW Transfer**	**1,250 MW Transfer**
On Peak Loss Benefit (MW)	36	90	20	63
Off Peak Loss Benefit (MW)	23	56	11	36

Item	Source	Public Power	Investor Owned	Total Project
Million Dollars Present Value per Million Dollars Spent [Investment Cost]	Exhibit 7	1.1851	1.5484	1.4501
Million Dollars Present Value per MW lost [Demand Cost]	Exhibit 9	1.2266	1.5712	1.4768
Million Dollars Present Value per MW lost [Low Energy Cost]	Exhibit 11	5.0456	3.7572	4.0689
Million Dollars Present Value per MW lost [High Energy Cost]	Exhibit 11	6.8741	5.1187	5.5434

PVRR Capital Cost	$ 161.56	$ 211.09	$ 197.69

Without & 0 MW Transfer			
PVRR Demand Benefit	$ 24.53	$ 31.42	$ 29.54
PVRR Energy Benefit (Low)	$ 100.91	$ 75.14	$ 81.38
PVRR Energy Benefit (High)	$ 137.48	$ 102.37	$ 110.87
Total Benefit (Low)	$ 125.44	$ 106.57	$ 110.91
Total Benefit (High)	$ 162.01	$ 133.80	$ 140.40
Without & 1,250 MW Transfer			
PVRR Demand Benefit	$ 77.27	$ 98.99	$ 93.04
PVRR Energy Benefit (Low)	$ 317.88	$ 236.70	$ 256.34
PVRR Energy Benefit (High)	$ 433.07	$ 322.48	$ 349.23
Total Benefit (Low)	$ 395.15	$ 335.69	$ 349.38
Total Benefit (High)	$ 510.34	$ 421.47	$ 442.27

With & 0 MW Transfer	Public Power	Investor Owned	Total Project
PVRR Demand Benefit	$ 44.16	$ 56.56	$ 53.16
PVRR Energy Benefit (Low)	$ 181.64	$ 135.26	$ 146.48
PVRR Energy Benefit (High)	$ 247.47	$ 184.27	$ 199.56
Total Benefit (Low)	$ 225.80	$ 191.82	$ 199.64
Total Benefit (High)	$ 291.62	$ 240.84	$ 252.73
With & 1,250 MW Transfer			
PVRR Demand Benefit	$ 110.39	$ 141.41	$ 132.91
PVRR Energy Benefit (Low)	$ 454.11	$ 338.15	$ 366.20
PVRR Energy Benefit (High)	$ 618.67	$ 460.69	$ 498.91
Total Benefit (Low)	$ 564.50	$ 479.55	$ 499.11
Total Benefit (High)	$ 729.06	$ 602.09	$ 631.81

Without & 0 MW Transfer			
PVRR Net Total Cost (Low)	$ (36.11)	$ (104.52)	$ (86.78)
PVRR Net Total Cost (High)	$ 0.46	$ (77.29)	$ (57.29)
Without & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 233.59	$ 124.60	$ 151.69
PVRR Net Total Cost (High)	$ 348.79	$ 210.38	$ 244.58
With & 0 MW Transfer			
PVRR Net Total Cost (Low)	$ 64.24	$ (19.27)	$ 1.95
PVRR Net Total Cost (High)	$ 130.07	$ 29.75	$ 55.04
With & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 402.94	$ 268.46	$ 301.42
PVRR Net Total Cost (High)	$ 567.50	$ 391.00	$ 434.12

Scenario	Total Project Cost	Probability	Expected Value
Without & 0 MW Transfer	$ (86.78)	25.0%	$ (21.69)
Without & 1,250 MW Transfer	$ 1.95	25.0%	$ 0.49
With & 0 MW Transfer	$ 151.69	25.0%	$ 37.92
With & 1,250 MW Transfer	$ 301.42	25.0%	$ 75.35
			$ 92.07
Without & 0 MW Transfer	$ (57.29)	25.0%	$ (14.32)
Without & 1,250 MW Transfer	$ 55.04	25.0%	$ 13.76
With & 0 MW Transfer	$ 244.58	25.0%	$ 61.15
With & 1,250 MW Transfer	$ 434.12	25.0%	$ 108.53
			$ 169.11

Data-Applicant Reply to IR 40	Million 2008 Dollars			
	Total Cost	500 kV Incremental	Base Cost	Percent Increase
Applicants Response	$ 594.50	$ 194.75	$ 399.75	49%

	With Winnipeg to Fargo		Without Winnipeg to Fargo	
Build and Operate at 500 kV	**0 MW Transfer**	**1,250 MW Transfer**	**0 MW Transfer**	**1,250 MW Transfer**
On Peak Loss Benefit (MW)	36	90	20	63
Off Peak Loss Benefit (MW)	23	56	11	36

Item	Source	Public Power	Investor Owned	Total Project
Million Dollars Present Value per Million Dollars Spent [Investment Cost]	Exhibit 7	1.1851	1.5484	1.4501
Million Dollars Present Value per MW lost [Demand Cost]	Exhibit 9	1.2266	1.5712	1.4768
Million Dollars Present Value per MW lost [Low Energy Cost]	Exhibit 11	5.0456	3.7572	4.0689
Million Dollars Present Value per MW lost [High Energy Cost]	Exhibit 11	6.8741	5.1187	5.5434

PVRR Capital Cost	$ 230.79	$ 301.56	$ 282.41

Without & 0 MW Transfer	**Public Power**	**Investor Owned**	**Total Project**
PVRR Demand Benefit	$ 24.53	$ 31.42	$ 29.54
PVRR Energy Benefit (Low)	$ 100.91	$ 75.14	$ 81.38
PVRR Energy Benefit (High)	$ 137.48	$ 102.37	$ 110.87
Total Benefit (Low)	$ 125.44	$ 106.57	$ 110.91
Total Benefit (High)	$ 162.01	$ 133.80	$ 140.40
Without & 1,250 MW Transfer			
PVRR Demand Benefit	$ 77.27	$ 98.99	$ 93.04
PVRR Energy Benefit (Low)	$ 317.88	$ 236.70	$ 256.34
PVRR Energy Benefit (High)	$ 433.07	$ 322.48	$ 349.23
Total Benefit (Low)	$ 395.15	$ 335.69	$ 349.38
Total Benefit (High)	$ 510.34	$ 421.47	$ 442.27

With & 0 MW Transfer	Public Power	Investor Owned	Total Project
PVRR Demand Benefit	$ 44.16	$ 56.56	$ 53.16
PVRR Energy Benefit (Low)	$ 181.64	$ 135.26	$ 146.48
PVRR Energy Benefit (High)	$ 247.47	$ 184.27	$ 199.56
Total Benefit (Low)	$ 225.80	$ 191.82	$ 199.64
Total Benefit (High)	$ 291.62	$ 240.84	$ 252.73
With & 1,250 MW Transfer			
PVRR Demand Benefit	$ 110.39	$ 141.41	$ 132.91
PVRR Energy Benefit (Low)	$ 454.11	$ 338.15	$ 366.20
PVRR Energy Benefit (High)	$ 618.67	$ 460.69	$ 498.91
Total Benefit (Low)	$ 564.50	$ 479.55	$ 499.11
Total Benefit (High)	$ 729.06	$ 602.09	$ 631.81

With & 0 MW Transfer	Public Power	Investor Owned	Total Project
PVRR Net Total Cost (Low)	$ (105.35)	$ (194.99)	$ (171.50)
PVRR Net Total Cost (High)	$ (68.78)	$ (167.76)	$ (142.01)
Without & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 164.36	$ 34.13	$ 66.96
PVRR Net Total Cost (High)	$ 279.55	$ 119.91	$ 159.86
With & 0 MW Transfer			
PVRR Net Total Cost (Low)	$ (4.99)	$ (109.74)	$ (82.77)
PVRR Net Total Cost (High)	$ 60.83	$ (60.72)	$ (29.69)
With & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 333.70	$ 178.00	$ 216.69
PVRR Net Total Cost (High)	$ 498.27	$ 300.54	$ 349.40

Scenario	Total Project Cost	Probability	Expected Value
Without & 0 MW Transfer	$ (171.50)	25.0%	$ (42.88)
Without & 1,250 MW Transfer	$ (82.77)	25.0%	$ (20.69)
With & 0 MW Transfer	$ 66.96	25.0%	$ 16.74
With & 1,250 MW Transfer	$ 216.69	25.0%	$ 54.17
			$ 7.35
Without & 0 MW Transfer	$ (142.01)	25.0%	$ (35.50)
Without & 1,250 MW Transfer	$ (29.69)	25.0%	$ (7.42)
With & 0 MW Transfer	$ 159.86	25.0%	$ 39.96
With & 1,250 MW Transfer	$ 349.40	25.0%	$ 87.35
			$ 84.39

Data-Applicant Reply to IR 40	Million 2008 Dollars			
	Total Cost	500 kV/345 kV Incremental	Base Cost	Percent Increase
Applicants Response	$ 653.10	$ 253.35	$ 399.75	63%

	With Winnipeg to Fargo		Without Winnipeg to Fargo	
Build and Operate at 500 kV	**0 MW Transfer**	**1,250 MW Transfer**	**0 MW Transfer**	**1,250 MW Transfer**
On Peak Loss Benefit (MW)	46	111	26	82
Off Peak Loss Benefit (MW)	28	69	14	46

Item	Source	Public Power	Investor Owned	Total Project
Million Dollars Present Value per Million Dollars Spent [Investment Cost]	Exhibit 7	1.1851	1.5484	1.4501
Million Dollars Present Value per MW lost [Demand Cost]	Exhibit 9	1.2266	1.5712	1.4768
Million Dollars Present Value per MW lost [Low Energy Cost]	Exhibit 11	5.0456	3.7572	4.0689
Million Dollars Present Value per MW lost [High Energy Cost]	Exhibit 11	6.8741	5.1187	5.5434

PVRR Capital Cost	$ 300.24	$ 392.30	$ 367.40

Without & 0 MW Transfer	**Public Power**	**Investor Owned**	**Total Project**
PVRR Demand Benefit	$ 31.89	$ 40.85	$ 38.40
PVRR Energy Benefit (Low)	$ 131.19	$ 97.69	$ 105.79
PVRR Energy Benefit (High)	$ 178.73	$ 133.09	$ 144.13
Total Benefit (Low)	$ 163.08	$ 138.54	$ 144.19
Total Benefit (High)	$ 210.62	$ 173.94	$ 182.52
Without & 1,250 MW Transfer			
PVRR Demand Benefit	$ 100.58	$ 128.84	$ 121.10
PVRR Energy Benefit (Low)	$ 413.74	$ 308.09	$ 333.65
PVRR Energy Benefit (High)	$ 563.68	$ 419.74	$ 454.56
Total Benefit (Low)	$ 514.32	$ 436.93	$ 454.74
Total Benefit (High)	$ 664.25	$ 548.57	$ 575.65

With & 0 MW Transfer	Public Power	Investor Owned	Total Project
PVRR Demand Benefit	$ 56.42	$ 72.28	$ 67.93
PVRR Energy Benefit (Low)	$ 232.10	$ 172.83	$ 187.17
PVRR Energy Benefit (High)	$ 316.21	$ 235.46	$ 255.00
Total Benefit (Low)	$ 288.52	$ 245.11	$ 255.10
Total Benefit (High)	$ 372.63	$ 307.74	$ 322.93
With & 1,250 MW Transfer			
PVRR Demand Benefit	$ 136.15	$ 174.40	$ 163.92
PVRR Energy Benefit (Low)	$ 560.07	$ 417.05	$ 451.65
PVRR Energy Benefit (High)	$ 763.03	$ 568.18	$ 615.32
Total Benefit (Low)	$ 696.21	$ 591.45	$ 615.57
Total Benefit (High)	$ 899.17	$ 742.58	$ 779.24

Without & 0 MW Transfer			
PVRR Net Total Cost (Low)	$ (137.17)	$ (253.76)	$ (223.21)
PVRR Net Total Cost (High)	$ (89.63)	$ (218.36)	$ (184.88)
Without & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 214.08	$ 44.62	$ 87.34
PVRR Net Total Cost (High)	$ 364.01	$ 156.27	$ 208.25
With & 0 MW Transfer			
PVRR Net Total Cost (Low)	$ (11.72)	$ (147.20)	$ (112.30)
PVRR Net Total Cost (High)	$ 72.39	$ (84.57)	$ (44.47)
With & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 395.97	$ 199.15	$ 248.17
PVRR Net Total Cost (High)	$ 598.93	$ 350.28	$ 411.84

Scenario	Total Project Cost	Probability	Expected Value
Without & 0 MW Transfer	$ (223.21)	25.0%	$ (55.80)
Without & 1,250 MW Transfer	$ (112.30)	25.0%	$ (28.07)
With & 0 MW Transfer	$ 87.34	25.0%	$ 21.84
With & 1,250 MW Transfer	$ 248.17	25.0%	$ 62.04
			$ (0.00)
Without & 0 MW Transfer	$ (184.88)	25.0%	$ (46.22)
Without & 1,250 MW Transfer	$ (44.47)	25.0%	$ (11.12)
With & 0 MW Transfer	$ 208.25	25.0%	$ 52.06
With & 1,250 MW Transfer	$ 411.84	25.0%	$ 102.96
			$ 97.69

Data-Applicant Reply to IR 40	Million $ (2008 $)			
	Total Cost	500 kV/345 kV Incremental	Base Cost (2008$)	Percent Increase
Applicants Response	$ 922.56	$ 522.81	$ 399.75	131%

	With Winnipeg to Fargo		Without Winnipeg to Fargo	
Build and Operate at 500 kV	**0 MW Transfer**	**1,250 MW Transfer**	**0 MW Transfer**	**1,250 MW Transfer**
On Peak Loss Benefit (MW)	46	111	26	82
Off Peak Loss Benefit (MW)	28	69	14	46

Item	Source	Public Power	Investor Owned	Total Project
Million Dollars Present Value per Million Dollars Spent [Investment Cost]	Exhibit 7	1.1851	1.5484	1.4501
Million Dollars Present Value per MW lost [Demand Cost]	Exhibit 9	1.2266	1.5712	1.4768
Million Dollars Present Value per MW lost [Low Energy Cost]	Exhibit 11	5.0456	3.7572	4.0689
Million Dollars Present Value per MW lost [High Energy Cost]	Exhibit 11	6.8741	5.1187	5.5434

PVRR Capital Cost	$ 619.56	$ 809.53	$ 758.14

Without & 0 MW Transfer	**Public Power**	**Investor Owned**	**Total Project**
PVRR Demand Benefit	$ 31.89	$ 40.85	$ 38.40
PVRR Energy Benefit (Low)	$ 131.19	$ 97.69	$ 105.79
PVRR Energy Benefit (High)	$ 178.73	$ 133.09	$ 144.13
Total Benefit (Low)	$ 163.08	$ 138.54	$ 144.19
Total Benefit (High)	$ 210.62	$ 173.94	$ 182.52
Without & 1,250 MW Transfer			
PVRR Demand Benefit	$ 100.58	$ 128.84	$ 121.10
PVRR Energy Benefit (Low)	$ 413.74	$ 308.09	$ 333.65
PVRR Energy Benefit (High)	$ 563.68	$ 419.74	$ 454.56
Total Benefit (Low)	$ 514.32	$ 436.93	$ 454.74
Total Benefit (High)	$ 664.25	$ 548.57	$ 575.65

With & 0 MW Transfer	Public Power	Investor Owned	Total Project
PVRR Demand Benefit	$ 56.42	$ 72.28	$ 67.93
PVRR Energy Benefit (Low)	$ 232.10	$ 172.83	$ 187.17
PVRR Energy Benefit (High)	$ 316.21	$ 235.46	$ 255.00
Total Benefit (Low)	$ 288.52	$ 245.11	$ 255.10
Total Benefit (High)	$ 372.63	$ 307.74	$ 322.93
With & 1,250 MW Transfer			
PVRR Demand Benefit	$ 136.15	$ 174.40	$ 163.92
PVRR Energy Benefit (Low)	$ 560.07	$ 417.05	$ 451.65
PVRR Energy Benefit (High)	$ 763.03	$ 568.18	$ 615.32
Total Benefit (Low)	$ 696.21	$ 591.45	$ 615.57
Total Benefit (High)	$ 899.17	$ 742.58	$ 779.24

Without & 0 MW Transfer			
PVRR Net Total Cost (Low)	$ (456.49)	$ (670.99)	$ (613.96)
PVRR Net Total Cost (High)	$ (408.95)	$ (635.59)	$ (575.62)
Without & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 214.08	$ 44.62	$ 87.34
PVRR Net Total Cost (High)	$ 364.01	$ 156.27	$ 208.25
With & 0 MW Transfer			
PVRR Net Total Cost (Low)	$ (11.72)	$ (147.20)	$ (112.30)
PVRR Net Total Cost (High)	$ 72.39	$ (84.57)	$ (44.47)
With & 1,250 MW Transfer			
PVRR Net Total Cost (Low)	$ 395.97	$ 199.15	$ 248.17
PVRR Net Total Cost (High)	$ 598.93	$ 350.28	$ 411.84

Scenario	Total Project Cost	Probability	Expected Value
Without & 0 MW Transfer	$ (613.96)	25.0%	$ (153.49)
Without & 1,250 MW Transfer	$ (112.30)	25.0%	$ (28.07)
With & 0 MW Transfer	$ 87.34	25.0%	$ 21.84
With & 1,250 MW Transfer	$ 248.17	25.0%	$ 62.04
			$ (97.69)
Without & 0 MW Transfer	$ (575.62)	25.0%	$ (143.90)
Without & 1,250 MW Transfer	$ (44.47)	25.0%	$ (11.12)
With & 0 MW Transfer	$ 208.25	25.0%	$ 52.06
With & 1,250 MW Transfer	$ 411.84	25.0%	$ 102.96
			$ -

Data-Applicant Reply to IR 40	Million $ (2008 $) Total Cost	Incremental Cost	Base Cost	Percent Increase
Applicants Numbers	$ 780.61	$ 180.61	$ 600.00	30%
Applicants Numbers	$ 854.52	$ 189.52	$ 665.00	28%

	With MV-BL Rebuild		Without MV-BL Rebuild	
Build and Operate at 500 kV	**1,200 MW Transfer**	**2,400 MW Transfer**	**1,200 MW Transfer**	**2,400 MW Transfer**
On Peak Loss Benefit (MW)	8	26	7	23
Off Peak Loss Benefit (MW)	6	19	4	15

Item	Source	Public Power	Investor Owned	Total Project
Million Dollars Present Value per Million Dollars Spent [Investment Cost]	Exhibit 7	1.1851	1.5484	1.4501
Million Dollars Present Value per MW lost [Demand Cost]	Exhibit 9	1.2266	1.5712	1.4768
Million Dollars Present Value per MW lost [Low Energy Cost]	Exhibit 11	5.0456	3.7572	4.0689
Million Dollars Present Value per MW lost [High Energy Cost]	Exhibit 11	6.8741	5.1187	5.5434

PVRR Capital Cost (Low)	$ 214.03	$ 279.65	$ 261.90
PVRR Capital Cost (High)	$ 224.60	$ 293.46	$ 274.83

Without & 1,200 MW Transfer			
PVRR Demand Benefit	$ 8.59	$ 11.00	$ 10.34
PVRR Energy Benefit (Low)	$ 35.32	$ 26.30	$ 28.48
PVRR Energy Benefit (High)	$ 48.12	$ 35.83	$ 38.80
Total Benefit (Low)	$ 43.91	$ 37.30	$ 38.82
Total Benefit (High)	$ 56.70	$ 46.83	$ 49.14
Without & 2,400 MW Transfer			
PVRR Demand Benefit	$ 28.21	$ 36.14	$ 33.97
PVRR Energy Benefit (Low)	$ 116.05	$ 86.42	$ 93.58
PVRR Energy Benefit (High)	$ 158.10	$ 117.73	$ 127.50
Total Benefit (Low)	$ 144.26	$ 122.55	$ 127.55
Total Benefit (High)	$ 186.32	$ 153.87	$ 161.46

With & 1,200 MW Transfer			
PVRR Demand Benefit	$ 9.81	$ 12.57	$ 11.81
PVRR Energy Benefit (Low)	$ 40.37	$ 30.06	$ 32.55
PVRR Energy Benefit (High)	$ 54.99	$ 40.95	$ 44.35
Total Benefit (Low)	$ 50.18	$ 42.63	$ 44.37
Total Benefit (High)	$ 64.81	$ 53.52	$ 56.16
With & 2,400 MW Transfer			
PVRR Demand Benefit	$ 31.89	$ 40.85	$ 38.40
PVRR Energy Benefit (Low)	$ 131.19	$ 97.69	$ 105.79
PVRR Energy Benefit (High)	$ 178.73	$ 133.09	$ 144.13
Total Benefit (Low)	$ 163.08	$ 138.54	$ 144.19
Total Benefit (High)	$ 210.62	$ 173.94	$ 182.52

Without & 1,200 MW Transfer			
PVRR Net Total Cost (Low)	$ (170.12)	$ (242.36)	$ (223.08)
PVRR Net Total Cost (High)	$ (167.89)	$ (246.63)	$ (225.69)
Without & 2,400 MW Transfer			
PVRR Net Total Cost (Low)	$ (69.77)	$ (157.10)	$ (134.35)
PVRR Net Total Cost (High)	$ (38.28)	$ (139.59)	$ (113.37)
With & 1,200 MW Transfer			
PVRR Net Total Cost (Low)	$ (163.85)	$ (237.03)	$ (217.54)
PVRR Net Total Cost (High)	$ (159.79)	$ (239.94)	$ (218.67)
With & 2,400 MW Transfer			
PVRR Net Total Cost (Low)	$ (50.95)	$ (141.12)	$ (117.72)
PVRR Net Total Cost (High)	$ (13.98)	$ (119.52)	$ (92.31)

161 kV--Rochester & La Crosse Areas	Source	Public Power	Investor Owned	Total Project
2011 Investment (Million 2005 $)	A-2, pg 159	$ 84.00		
Inflation Rate		2.5%		
2011 Investment (Million 2011 $)		$ 97.41	$ 97.414	$ 97.414
Transmission Fixed Charge Rate		7.70%	12.75%	11.20%
Annual Revenue Requirement		$ 7.501	$ 12.420	$ 10.910
Transmission Life		35	35	35
Annual Revenue Requirement		$ 7.501	$ 12.420	$ 10.910
Nominal Discount Rate		5.50%	7.60%	7.00%
Present Value of Revenue Requirements--Investment Cost (2011)		$ 115.44	$ 150.84	$ 141.26
Present Value of Revenue Requirements--Investment Cost (2008)		$ 98.31	$ 121.08	$ 115.31

161 kV--La Crosse Area	Source	Public Power	Investor Owned	Total Project
2014 Investment (Million 2005 $)	A-2, pg 161	$ 93.30		
Inflation Rate		2.5%		
2014 Investment (Million 2014 $)		$ 116.52	$116.519	$ 116.519
Transmission Fixed Charge Rate		7.70%	12.75%	11.20%
Annual Revenue Requirement		$ 8.972	$ 14.856	$ 13.050
Transmission Life		35	35	35
Annual Revenue Requirement		$ 8.972	$ 14.856	$ 13.050
Nominal Discount Rate		5.50%	7.60%	7.00%
Present Value of Revenue Requirements--Investment Cost (2014)		$ 138.08	$ 180.42	$ 168.97
Present Value of Revenue Requirements--Investment Cost (2008)		$ 100.14	$ 116.26	$ 112.59

161 kV--Rochester Area	Source	Public Power	Investor Owned	Total Project
2033 Investment (Million 2005 $)	A-2, pg 160	$ 53.00		
Inflation Rate		2.5%		
2033 Investment (Million 2033 $)		$ 105.81	$105.814	$ 105.814
Transmission Fixed Charge Rate		7.70%	12.75%	11.20%
Annual Revenue Requirement		$ 8.148	$ 13.491	$ 11.851
Transmission Life		35	35	35
Annual Revenue Requirement		$ 8.148	$ 13.491	$ 11.851
Nominal Discount Rate		5.50%	7.60%	7.00%
Present Value of Revenue Requirements--Investment Cost (2033)		$ 125.40	$ 163.85	$ 153.45
Present Value of Revenue Requirements--Investment Cost (2008)		$ 32.88	$ 26.25	$ 28.27

161 kV Total Present Value of Revenue Requirements--Investment Cost (2008)		$ 231.34	$ 263.59	$ 256.18

345 kV--Rochester & La Crosse Areas	Source	Public Power	Investor Owned	Total Project
2015 Investment (Million 2005 $)	A-2, pg 159	$ 191.63		
Inflation Rate		2.5%		
2015 Investment (Million 2015 $)		$ 245.30	$245.304	$ 245.304
Transmission Fixed Charge Rate		7.70%	12.75%	11.20%
Annual Revenue Requirement		$ 18.888	$ 31.276	$ 27.474
Transmission Life		35	35	35
Annual Revenue Requirement		$ 18.888	$ 31.276	$ 27.474
Nominal Discount Rate		5.50%	7.60%	7.00%
Present Value of Revenue Requirements--Investment Cost (2015)		$ 290.70	$ 379.84	$ 355.72
Present Value of Revenue Requirements--Investment Cost (2008)		$ 199.84	$ 227.46	$ 221.53

345 kV minus 161 kV	Public Power	Investor Owned	Total Project
Differential Present Value of Revenue Requirements--Investment Cost (2008)	$ (31.50)	$ (36.12)	$ (34.65)

345 kV Loss Analysis	Source	Public Power	Investor Owned	Total Project
On Peak Loss Benefit	IR 44	3.5	3.5	3.5
Million Dollars Present Value per MW lost [Demand Cost]	Exhibit 9	1.2266	1.5712	1.4768
Million Dollars Present Value per MW lost [Low Energy Cost]	Exhibit 11	5.0456	3.7572	4.0689
Million Dollars Present Value per MW lost [High Energy Cost]	Exhibit 11	6.8741	5.1187	5.5434
PVRR Demand Benefit		$ 4.29	$ 5.50	$ 5.17
PVRR Energy Benefit (Low)		$ 17.66	$ 13.15	$ 14.24
PVRR Energy Benefit (High)		$ 24.06	$ 17.92	$ 19.40
Total Loss Benefit (Low)		$ 21.95	$ 18.65	$ 19.41
Total Loss Benefit (High)		$ 28.35	$ 23.41	$ 24.57

345 kV Incremental Benefit	Public Power	Investor Owned	Total Project
Net Differential (Low)	$ (53.45)	$ (54.77)	$ (54.06)
Net Differential (High)	$ (59.85)	$ (59.54)	$ (59.22)

MINNESOTA DEPARTMENT OF COMMERCE

85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198
www.commerce.state.mn.us
651.296.4026 FAX 651.296.1959
An equal opportunity employer

January 15, 2008

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 7th Place East
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce**
Docket No. E999/M-07-1028

Dear Dr. Haar:

Attached are the comments of the Energy Division of the Minnesota Department of Commerce (Department) in the following matter:

2007 Minnesota Biennial Transmission Projects Report.

The petition was filed on November 1, 2007. The petitioner is:

Alan R. Mitchell
Lindquist & Vennum P.L.L.P.
4200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402-2274

The Department recommends that the Minnesota Transmission Owners office reply comments on certain issues. The Department is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ STEVE RAKOW
Rates Analyst

SR/sm
Attachment

2. *Department*

During the past transmission planning biennium several CN petitions were filed with the Commission.[4] In these dockets, the applicant's economic analysis of alternatives often was based upon engineering studies done during the transmission planning process. In certain cases no significant economic analysis of alternatives was done at either the engineering studies or in the CN. During the course of preparing these comments the Department reviewed the economic analysis of the alternatives contained in several CN petitions. Based upon this review the Department has the following comments for future transmission studies. The Department's goal is to explore with MTO the possibility of arriving at mutually agreeable methods and/or input values to use in economic analysis of transmission alternatives in future studies and subsequent CN proceedings.

a. Use of Externality Values

In CN petitions the applicants typically analyzed three different categories of costs in the process of selecting alternatives:

1. cost of the capital invested;
2. cost of the demand losses; and
3. cost of the energy losses.

These three categories do not include use of the Commission's externality values. Minnesota Statutes §216B.2422 subdivision 3 states:

> (a) The Commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the Commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the Commission, including resource plan and certificate of need proceedings.

[4] See:

- CapX Phase 1—Docket No. ET2, E002/CN-06-1115;
- Chisago to Apple River—Docket No. E002, ET3/CN-04-1176;
- Appleton to Canby—Docket No. E017/CN-06-0677;
- Mud Lake to Wilson Lake—Docket No. E002/CN-06-0367;
- BRIGO—Docket No. E002/CN-06-0154; and
- Big Stone II Outlet—Docket No. E017 et al /CN-05-0619.

Based upon an initial review of this language, it is not immediately clear whether subdivision 3 should apply to transmission proceedings. The Department notes that:

1) the Commission has not been precluded from applying the approved externality values in proceedings where transmission resources are acquired;
2) information regarding generation resources is required to be discussed as an alternative in certificate of need petitions for transmission resources;[5] and
3) there is no analytical difference between externalities resulting from approving a new generation resource and approving a new transmission resource since the transmission system influences externalities in the form of the energy produced to account for transmission losses.

This issue does have the potential to impact the choice of alternatives. Specifically, when the MTO's members exclude externality costs, the cost of energy used is too low in that it does not include all pertinent costs. In consequence, MTO's members will undervalue energy losses and thus bias their analysis against the more energy-efficient alternatives. Therefore, the Department recommends that the Commission require MTO's members, in future transmission planning studies that are intended to support CN petitions in Minnesota and in the actual CN petitions themselves, to calculate their analyses with no externalities as well as with low and high externality values approved by the Commission.[6] While no one method of applying the values should be required, examples of how to perform such analysis can be found in the Department's direct testimony in the dockets cited previously.

Further, while Minnesota Statutes §216H.06 does not require the use of the Commission's recently established range of costs of future carbon dioxide (CO_2) regulation, the Department recommends that the Commission require the use of those values as well. Essentially, a less energy-efficient transmission system will have greater energy losses requiring more energy to be produced by the generation system and, in turn, more CO_2. Thus, transmission system choices will impact exposure to the costs of future CO_2 regulation. Therefore, to adequately consider the costs of future CO_2 regulation, the Commission-established values must be considered in transmission proceedings as well as generation proceedings.

b. Discount Rates

In transmission planning studies and CN petitions, utilities typically apply a single, nominal discount rate to all of the costs that are analyzed. However, some of the costs to which the discount rate is applied (specifically, energy costs) are often expressed in real dollars. Applying a nominal discount rate to a real dollar value is an error that will skew the results of the analysis. The Department intends to review each applicant's calculations in future CN proceedings to

[5] See Minnesota Rules 7849.0260 B (1). In addition, under certain circumstances, transmission upgrades or construction may substitute for generation construction and visa versa.
[6] To be clear, the requirement should apply to transmission studies completed after the date of the Commission's Order in this proceeding, even if the underlying CN is not filed for some time.

ensure this error is not repeated. However, the Department is concerned that the error and its resulting effects on costs is embedded in the MTO utilities' planning and engineering study processes and may improperly influence the selection of alternatives during the early stages.

Specifically, a nominal discount rate will be inappropriately high when applied to real values in an inflationary environment (as opposed to a deflationary environment). Since the issue appears to be specific to energy costs, the error will lead MTO's members to undervalue energy losses and thus bias their analysis against the more energy-efficient alternatives. Therefore, the Department recommends that MTO take steps to ensure that the economic analysis underlying transmission planning studies and CN petitions properly identifies cost values as real or nominal and select the corresponding (real or nominal) discount rate. MTO should explain these steps in reply comments.

c. Energy cost values

In transmission planning studies and CN petitions utilities typically use an assumed cost of energy to value the energy losses when assessing alternatives. In the CN petitions reviewed (when specified) the assumed cost of energy was usually in the $20 to $30 per MWh range. While values in the $20 to $30 per MWh range may have been appropriate in the past, recent data indicate that such values are significantly lower than actual energy prices. Specifically, the Department calculated the day ahead, locational marginal price (LMP) for the Minnesota hub on a 365-day rolling average basis. The value has been in the range of $50 to $55 since March, 2007.

Further, the Department has used the Minnesota hub LMP to value energy losses in recent CN proceedings since the LMP represents the cost of the last unit of energy. It would be useful for the Department if MTO would offer reply comments regarding the proper set of LMP data to apply to energy losses. Specifically, MTO should address, first, whether the Minnesota hub represents a reasonable set of data to use for most CN petitions or whether some other set of data are more appropriate. Second, it is also unclear at this time whether a 365-day average of all hours should be used, a subset of data such as only off-peak or only on-peak hours, or a weighted average of the hours would be best to value energy losses. The question is, what data best reflects the load shape of the losses? It would be useful for the Department if MTO would offer reply comments regarding the proper hours to use when valuing energy losses. Third, the Department would welcome any comments MTO has on the use of the Minnesota Hub LMP for valuing energy losses. That is, is the day ahead LMP the correct value to use? If not, then what, in MTO's estimation, should be used instead?

As with the discount rate discussion above, the Department is concerned that the cost of energy losses is embedded in the MTO's members' planning processes and may improperly influence the selection of alternatives during the early stages. Specifically, if MTO's members use a cost of energy that is too low, then they will undervalue energy losses and thus bias the analysis against the more energy-efficient alternatives. Therefore, the Department recommends that MTO

take steps to ensure that the economic analysis underlying transmission planning studies and CN petitions properly identifies the cost of energy losses. The Department requests MTO to explain these steps in reply comments.

d. Period of energy losses

In transmission planning studies and CN petitions utilities typically use, as explained above, a specific period to value the energy losses when assessing alternatives. In the CN petitions reviewed (when specified) the period of analysis for energy losses sometimes was different than for other cost categories. Specifically, energy losses were sometimes valued over 20 years while the period of analysis for all other cost categories was substantially longer. To the Department it appears inappropriate to use differing periods of analysis for different cost factors. In this case, MTO's members have often applied a shorter period of analysis to energy costs than the other costs. In effect the MTO's members' analysis under-weights energy costs in the overall formula and thus biases the analysis against the more energy-efficient alternatives. Therefore, the Department recommends that MTO take steps to ensure that the economic analysis underlying transmission planning studies and CN petitions properly identifies the period of analysis for energy losses. The Department recommends that MTO explain these steps in reply comments.

e. Demand cost values

In transmission planning studies and CN petitions utilities typically use an assumed cost of capacity to value the demand losses when assessing alternatives. In the CN petitions reviewed (when specified) the cost of baseload capacity was assumed to be about $1,000 per kW. While a base load capacity cost of $1,000 per kW may have been appropriate in the past, recent data indicate that such values are significantly low. Specifically, the data available in the proceeding regarding the proposal of Excelsior Energy (E6472/M-05-1993), the Xcel baseload filing, (E002/CN-06-1518), and the Big Stone 2 proposal (E017 et al/CN-05-619) all indicate that baseload capacity costs are substantially higher, typically in the neighborhood of $2,000 per kW. While the cost used in the past may be low, it may no longer be appropriate to even include baseload resources as an avoided cost. Specifically, Minnesota Statutes §216H.03 subd. 3 (and arguably the renewable energy objectives of Minnesota Statues §216B.1691) may reduce or eliminate consideration of baseload facilities for the foreseeable future.

As with the other issues discussed above, the Department is concerned that the cost of base load capacity, and thus the cost of demand losses embedded in MTO's members' planning processes may improperly influence the selection of alternatives at the planning and/or CN stages. Specifically, when MTO's members undervalue base load capacity costs then the cost of demand losses is too low. In consequence, MTO's members will undervalue demand losses and thus bias the analysis against the more energy-efficient alternatives. However, if no baseload plants can be avoided due to Minnesota Statutes §216H.03 subd. 3 by improving energy efficiency the opposite will occur. Therefore, the Department recommends that MTO take steps to ensure that the economic analysis underlying transmission planning studies and CN petitions properly identifies

the cost of base load capacity and/or the appropriateness of including baseload capacity in the demand loss valuation calculations. The Department recommends that MTO explain these steps in reply comments.

f. Fixed Charge Rates

In transmission planning studies and CN petitions MTO's members typically use fixed charge rates to value the capital cost of the investment and the value of demand losses when assessing alternatives. In certain CN petitions the assumed fixed charge rate was often about 15 percent of total costs. While a fixed charge rate of 15 percent may have been appropriate in the past, recent data indicate that such values may be too high. Specifically, the data available to the Department in the Big Stone 2 proceeding (E017 et al/CN-05-619) indicates that fixed charge rates are substantially lower, typically in the neighborhood of 12 percent for investor-owned utilities and 8 percent for publicly-owned utilities (i.e., cooperative and municipal).

As with the other issues discussed above, the Department is concerned that the fixed charge rate embedded in MTO's members' planning processes may improperly influence the selection of alternatives at the planning and/or CN stages. Specifically, there are two effects when MTO's members use a fixed charge rate that is too high. The first effect is that the cost of demand losses is also too high. The second effect is that the investment cost is too high. The consequence of the first effect is that MTO will bias the analysis towards alternatives that rely more on energy than on capacity. The consequence of the second effect is that MTO's members will bias their analysis towards alternatives that are less capital intensive. Therefore, the Department recommends that MTO take steps to ensure that the economic analysis underlying transmission planning studies and CN petitions properly identifies the fixed charge rates. MTO should explain these steps in reply comments.

g. Quantity of Energy Losses

The Department has noted that utilities have often simulated off-peak conditions using 70 percent of the peak load. The questions the Department has are:

- Is 70 percent the correct level?
- What is the factual basis for use of this level?

The Department recommends that MTO comment on the appropriate method for assessing the quantity of energy losses during certificate of need proceedings.

h. Recommendations Regarding Alternatives Analysis

The Department's recommendations are grouped into two areas. One group requests Commission action and a second group requests reply comments from MTO. Regarding recommendations for Commission action, the Department recommends that the Commission

require MTO's members, in future transmission planning studies that are intended to support CN petitions in Minnesota and in the actual CN petitions themselves, to use the Commission's no, low, and high externality values in the economic analysis. Further, while Minnesota Statutes §216H.06 does not require the use of the Commission's recently established range of costs of future CO_2 regulation, the Department recommends that the Commission require the use of those values as well.

Regarding reply comments from MTO, the Department recommends that MTO explain the steps it will take to ensure that the economic analysis underlying transmission planning studies and CN petitions properly identifies:

- cost values as real or nominal and select the corresponding discount rate;
- the cost of energy losses;
- the period of analysis for energy losses;
- the quantity of energy losses;
- the cost of base load capacity in the demand loss valuation calculations; and
- the fixed charge rates.

Finally, the Department requests reply comments from MTO regarding:

- the proper set of LMP data to apply to energy losses; and
- the proper hours to use when valuing energy losses.

D. MAINTENANCE ACTIVITIES

As mentioned by MTO in chapter 8, the Department requested that each MTO member provide data on the number of miles of transmission and total operations and maintenance (O&M) costs, both historical data and future forecasts. The Department's goal was to use this data to determine a method for assessing the overall reasonableness of the transmission maintenance activities of each MTO member from a budgetary perspective rather than a physical perspective. However, the Department was unable to arrive at a satisfactory method at this time.

While the Department was unable within this timeframe to develop a metric applicable to all utilities, the Department was able to develop a method that may be applicable to investor-owned utilities. The Department compared the past average annual O&M costs to the budget figures from each utility's last rate case. This data is presented in below in Table 4. The Department also compared the forecasted average annual O&M cost to the rate case budget figures. This data is presented in below in Table 5.