Preliminary Results of a Feasibility Study for 660 MW of Generation in Chisago County Minnesota

Prepared for:
An Independent Power Producer

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Overview

This report summarizes the results of a Generation Interconnection Study performed by Xcel Energy Transmission Services to determine what facilities are required to interconnect 660 MW of generation on the 345kV system at Xcel Energy's Chisago substation. The interconnection point studied was on the 345kV bus at Chisago substation with a radial 345kV line to the IPP's site.

The objective of this study is to determine the facilities necessary to add the 660MW of generation at this location without violating Xcel Energy steady-state planning criteria. Both interconnection costs and infrastructure improvements have been estimated and are included with this report**. We studied the infrastructure impacts on the system as if the power was being sold to Xcel Energy. Should this not be the final outcome, a subset of this study will have to be re-run to evaluate the flows with the energy being sold to a different market.**

Using PSS/E, a load flow study was performed to evaluate the system with the generation addition during both system intact, single, and a few select double contingency situations. Descriptions of the system model, contingencies, and assumptions are discussed in the following sections of this report, followed by the results of the power flow analysis. **A dynamic simulation analysis has not been requested or performed as of the date of this study. Additional interconnection and infrastructure facilities may be required as a result of the dynamic simulation analysis.**

Conclusions

Based on this study, it has been determined that in order to connect the 660 MW of generation, system improvements will be required. The costs are summarized below:

Interconnect on the 345kV bus at Chisago Co. Substation:

Estimated Interconnection Costs	$ 1.25 million
Option 2: Xcel Energy System Infrastructure Costs:	$ 38.45 million
Option 3: Xcel Energy System Infrastructure Costs:	$ 36.35 million
Total Option 2 Estimated Cost:	**$ 39.7 million**
Total Option 3 Estimated Cost:	**$ 37.6 million**

These estimates are discussed in greater detail in the following sections of this report.

Please note that these estimates are preliminary indicative cost estimates and should be considered as such. Costs and timelines may vary significantly due to unforeseen permitting, right-of-way, material availability or construction issues.

Also, note again that these infrastructure costs are based on selling the power to Xcel Energy. . If the power were not for delivery to a Network Service Customer, a subset of this study would have to be re-run to evaluate the flows with the energy being sold to a different market.

1.0 Introduction

1.1 Description of Project

An independent power producer has requested an interconnection to NSP's transmission system in Chisago County, Minnesota for a 660 MW power plant. NSP is a utility subsidiary of Xcel Energy. The proposed in-service date is May 2005. The study assumes plant's output is to be sold to Xcel Energy, and the construction and permitting lead times begin when the interconnection and/or transmission agreements are signed.

1.2 Scope of Study

A generator interconnection study determines the interconnection and infrastructure facilities required to interconnect a generator to NSP's system while meeting MAPP planning criteria. Steady-state powerflow cases are run to determine if the transmission system is capable of receiving the plant's power during normal and post-contingency conditions. A fault analysis is performed to determine appropriate ratings for the new equipment. Power transfer distribution factors (PTDF) are calculated to determine the impacts of the new generation plant on MAPP transmission interfaces. Dynamic simulations are also performed to assess impact of the transmission system's dynamic performance during contingencies. Indicative interconnection facility cost estimates and preliminary schedules are developed by Substation and Transmission Engineering. If infrastructure upgrades are required, cost estimates and preliminary construction schedules are determined.

1.3 Planning Criteria

1.3.1 Steady State Criteria

Mid-Continent Area Power Pool (MAPP), of which Xcel Energy is a member, has established a standard for design and operation of the regional transmission network. The *MAPP Reliability Handbook* describes these standards in *Section 5 - Operating Review Subcommittee, Appendix A – MAPP Operating Studies Manual* and in *Section 8 - MAPP System Design and Operating Standards*. The voltage on load-serving buses under steady-state conditions (pre- and post-disturbance) with all lines in service must be maintained within the voltage limits as described. Similarly, pre- and post-disturbance element loadings must be as specified in the MAPP Operating Studies Manual.

A summary of Xcel Energy's planning criteria as specified in the MAPP Operating Studies Manual is shown in Table 1.3.1.

Table 1.3.1 – Steady-State Planning Criteria

Limits	System Intact Condition	Post-Contingency Condition
Transmission Line Loading	100% of Rating	110% of rating for single contingency. Sag limit of line for double contingency.
Transformer Loading	100% of Rating	130% post-contingency if pre-contingency loading is below 90% 110% post-contingency if pre-contingency loading is above 90%
Generator Bus Voltage	0.95 to 1.10 per unit	0.95 to 1.10 per unit
Load Bus Voltage	Twin Cities metro 0.92 to 1.10 per unit. Outside TC Metro 0.90 to 1.10 per unit.	Twin Cities Metro 0.92 to 1.10 per unit. Outside TC Metro 0.90 to 1.10 per unit.

Post-contingent transmission line loadings and bus voltages must be returned to system intact levels after the readjustment period of ten to thirty minutes as per MAPP System Design and Operating Standards. Generation may have to be curtailed to return facility loadings to a normal loading levels.

Under special circumstances, a small number of bus voltages may be permitted to rise to 1.10 per unit. This typically occurs during extreme light load conditions. The instantaneous voltage rise or drop due to capacitor switching during system intact conditions is limited to no greater than 3.0%.

Circuit loading and bus voltage violations of transmission between 69 and 345 kV in the NSP, Great River Energy (GRE), and Dairyland Cooperative Power (DPC) control areas are reported. Because the planning criteria are different between utilities, all circuit loadings above 100% of rating-A are flagged.

1.3.2 Dynamic Criteria

Operation of the power system must comply with the MAPP Operating Studies Manual criteria and the NERC Planning Standards. The MAPP criteria requires that voltages in the study area do not swing below 0.70 per unit with the exception of a few specific buses that have more stringent requirements. This set of transient voltage criteria has also been applied; the buses with specific transient voltage criteria are shown in Table 1.3.2.1

Table 1.3.2.1 - Transient Voltage Criteria

Bus	Min or	Max	Bus	Min or	Max
Dorsey 230	0.70	1.25	Forbes 230	0.82	1.15
Arrowhead 230	0.82	1.15	Running 230	0.70	1.20
Running SWCAP	0.70	1.20	Littlefork 115	0.70	1.20
Riverton 230	0.82	1.15	Drayton 230	0.80	1.15
Wahpeton 230	0.80	1.18	Center DC 230	0.82	1.15
Tioga 230	0.80	1.15	Dickinson 345	0.70	1.17
Coal Creek 230	0.70	1.18	Watertown 345	0.75	1.18
Boise 115	0.82	1.15	Ramsey 230	0.70	1.65
Hubbard 230	0.82	1.20			

In addition, there is a criterion for Twin Cities voltage levels requiring that the Prairie Island 4.16 kV bus voltage cannot fall below 78% of nominal for more than 60 cycles. The dynamic swings at the 230 kV cross-border interconnections' out-of-step tripping buses (Drayton, Ft. Frances, Moranville, Rugby, and Tioga) must respect the relay margins defined in the Operating Reliability Subcommittee, Operating Studies Manual in order to ensure cascade tripping of the Canada-US interconnections does not occur. System performance was evaluated using the criteria described above.

2.0 System Description and Modeling

2.1 Base Models

The power flow analysis was performed using two cases, summer peak and off peak year 2005 load flow from the 2001 series MAPP models. The peak situation models 100% system peak load, high generation and low transfers, while the off peak situation models approximately 70% system peak load and high transfers. Export levels in the cases are listed below.

Table 2.1.1 – Transfer Levels in Base Case

Interface	Peak Level in MVA	Off-Peak Level in MVA
Manitoba Hydro	845	1950
North Dakota Export	2175	2175
Minnesota/Wisconsin Export (MWSI)	770	1515

2.2 Project Specific Changes to the Base Cases

After pulling these above described base cases from the MAPP model library; the following modifications were made to the Chisago Co. area:

2.2.1 Loads
NSP distribution loads in the vicinity of the generation interconnection were validated and updated per forecast 2005 peak values.

2.2.2 King Generation Interconnection
Xcel Energy has received an initial interconnection request to increase the output of the A.S. King plant from 571 MW to 670 MW. The generation at King for the purpose of this study was modeled at the 670 MW level.

2.2.3 Harvey – Glenboro
The Harvey-Glenboro 230 kV line was added to the summer off-peak case. Xcel Energy topology corrections prepared for the MAPP 2002 Series models were also applied to the models.

2.0 System Description and Modeling

2.1 Area Generation Levels Assumed

For both the peak and off peak conditions different generation levels were studied. Power flows were run with both default economic dispatch generation levels, and also with all generation in the local area on. The difference was made up by turning down the swing machine in the peak cases, and simulating a sell to MAIN in the off-peak cases.

2.2 Proposed Generator Modeling

The interconnection involves connecting the generator directly to the 345kV bus at Chisago substation as shown in Appendix A. The PSS/E idev file used to simulate this interconnection is also included in Appendix A. This configuration needs various interconnection and infrastructure facilities built or upgraded which are described in Section 4.0.

3.0 Steady – State Powerflow Analysis/Solutions

3.1 Methodology
Power Technology's PSS/E program was used to perform this analysis. Steady-state powerflow solutions had the following controls enabled: automatic adjustment of transformer taps, phase shift angles, area interchange and HVDC transformer taps. Within PSS/E, the activity ACCC was used as a first check of the entire system to find problem areas. Once these areas were

identified, individual powerflows were run to give more accurate results within these areas. The network contingency calculation activity, ACCC, calculates full AC power flow solutions for a specified set of contingency cases. For the contingency cases given, for example the Minneapolis/ St. Paul area as in this study, all possible single contingencies 69kV and above are run to find impacts on the system. Immediate inner-metro area double contingencies 115kV and above were also run.

3.2 Existing System Performance

The ACCC activity runs all contingencies in the area and, therefore, provides an excellent screening tool to determine if the generator addition results in violation of the planning criteria. Initially ACCC was run on the existing system for the four cases used: Peak load with default economic dispatch of generators, peak load with all local area generation on as well as economic dispatch, off-peak load with default economic dispatch of generators and off-peak load with all local area generation on as well as economic dispatch. The results were put aside to be later compared with the post-new generation results to find the most accurate set of violations strictly caused by the proposed new generation. The existing system results are included in Appendix B of this report.

3.3 System Performance with Generation Addition

The activity ACCC was run on each of the four base cases, and the results were compared against the existing system performance results. Any planning criteria violations that appeared to be caused by the generator were added to spreadsheets, and put aside for later review. Following the collection of this data, each contingency in question was run as in individual powerflow to validate the AC results.

4.0 Interconnection and Infrastructure Facilities

Following the steady-state powerflow analysis, it was determined that infrastructure upgrades were needed to handle the 660MW of new generation. These facilities are listed below, followed by the indicative cost estimates. **This section is based on the assumption that the plant output is being sold to Xcel Energy or another network service customer in the Twin Cities metro area**. Some to all of these improvements may also be needed to sell the output to other markets, but those options were not studied at this time.

4.1 Upgrades and Indicative Cost Estimates

4.1.1 Interconnection Facilities Required

The generator will be connected to the 345kV bus at Chisago Substation. The breaker addition required, and bus and breaker configuration are shown in greater detail in Appendix A.

Total Estimated Cost: $1.25 million for all options

4.1.2 Infrastructure Upgrades Required

- Option 2:
    - New 345kV line, built with 954 ACSR, double circuited overhead built for 345/345kV, operated at 230kV/345kV with existing 230 kV line from just outside Chisago Substation to the Red Rock Substation 345kV bus. This is 45 miles of new line on existing right-of-way.
        - Estimated Cost : $33 million
    - Expand Chisago Substation for 345kV new line termination for the line to Red Rock
        - Estimated Cost: $2.65 million

- 345kV modifications at Red Rock Substation to accommodate new line termination
  - Estimated Cost: $2.8 million
- **Option 2 Total Estimated Infrastructure Cost: $38.45 million**

- Option 3:
  - 31.6 miles of double circuit 345kV, operated at 230kV/115kV.
    - Estimated Cost: $700K/mile = $22 million
  - 8.7 miles of 115kV conductor on the empty side of the existing Lone Lake – King 115kV line and 0.6 miles of new 115kV from Oak Park Substation to King Substation.
    - Estimated Cost: $1 million
  - Expand Chisago Substation for 230kV line terminations with two 336 MVA transformers, and 115kV line termination for line to King.
    - Estimated Cost: $14 million
  - New 115kV line termination at King Substation.
    - Estimated Cost: $600K
  - **Option 3 Total Estimated Infrastructure Cost: $36.35 million**

Figure 4.1.2.1 and 4.1.2.2 below show the two infrastructure options with the necessary upgrades indicated.

Note: Option 1 was a 'reconductor all option' which was dismissed early in the study process and being too expensive and impractical, and therefore is not shown in a figure below or in the cost estimates.

Figure 4.1.2.1 – Option 2 Post Generation and Upgrades System Diagram

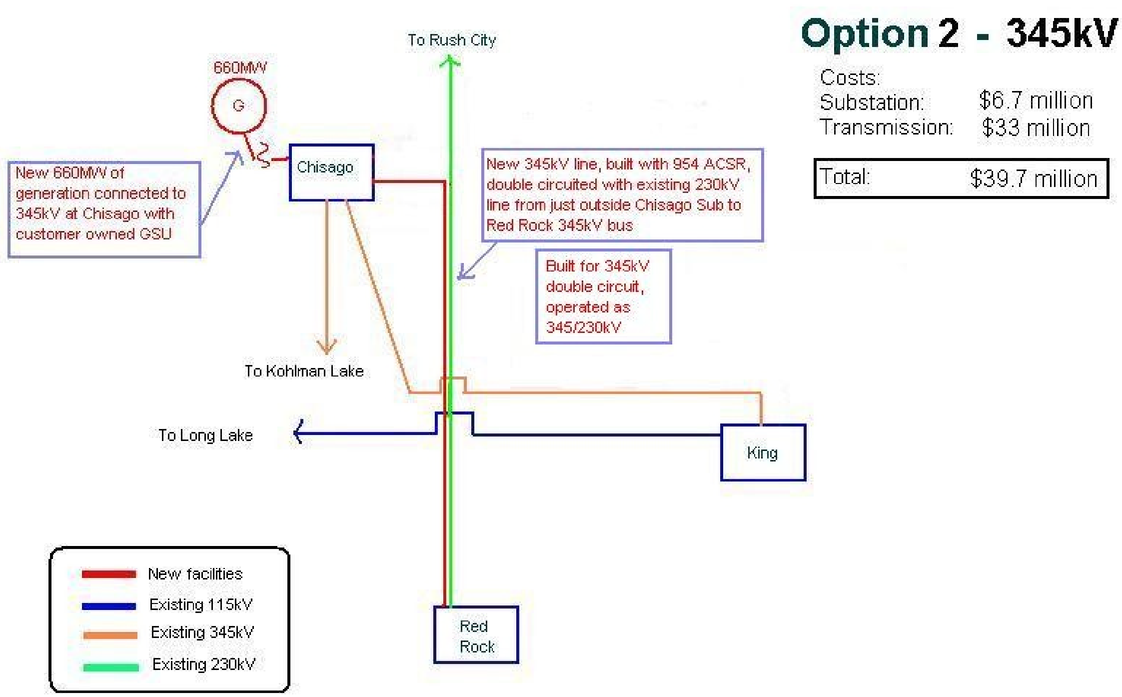
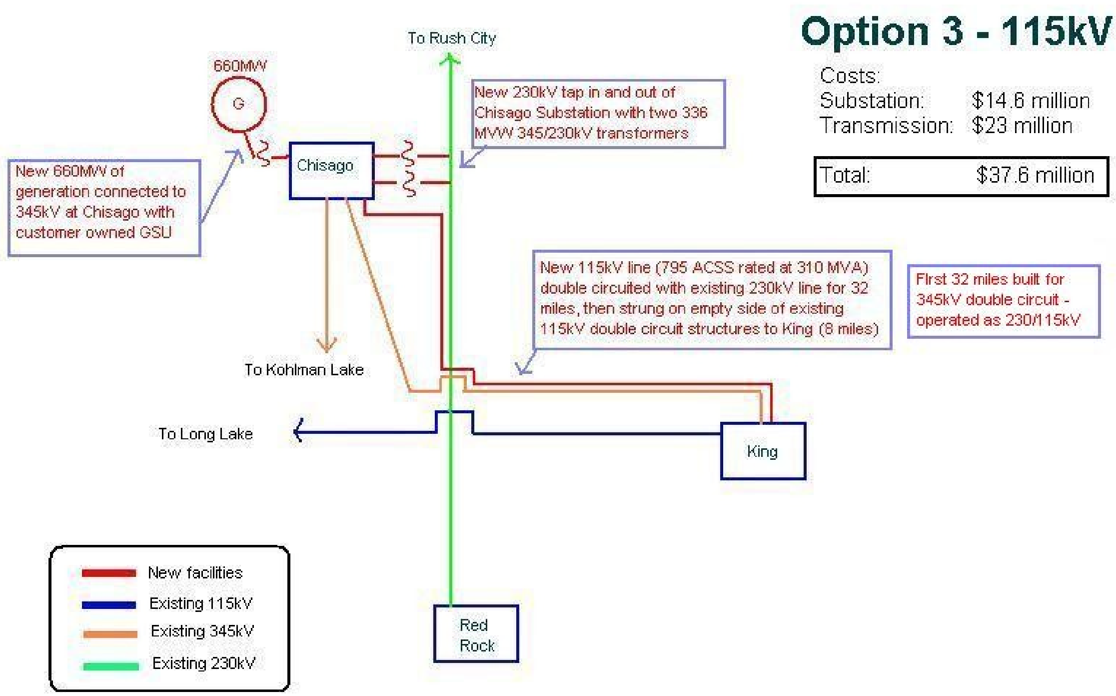


Figure 4.1.2.2 – Option 3 Post Generation and Upgrades System Diagram



4.2 Constrained Interface Analysis

A generator violates the MAPP Constrained Interface criteria if at least +5% of the new generation output is impressed upon any MAPP interface which has zero or negative Available Transfer Capability (ATC), or drives the ATC negative.

4.2.1 Generation to Generation Simulation - To make up for the 660 MW of generation at the proposed site, Sherco machine #1 is reduced by 660 MW. The new 660 MW generator does not violate any of the interface criteria for the generation to generation scenario.

4.5.2 Generation to Load Simulation – To make up for the 660 MW of generation at the proposed site, NSP-Minnesota & Wisconsin area load is scaled up by 660 MW. The new 660 MW generator violates the MWSI interface with more than 5% of the new generation crossing the interface for this generation to load scenario. **If this generation is to be sold to Xcel Energy to serve network load, this issue will have to be resolved and may result in additional interconnection and/or infrastructure costs.**

The output for all of these scenarios is included in Appendix E of this report

5.0 Dynamic Analysis – Stability

Dynamic simulations analysis has not been completed at the time of this reports publication. Additional interconnection and infrastructure upgrades may be required as determined by this analysis.

6.0 Caveats

All of the system improvements that have been identified in this report are believed to be adequate to meet relevant MAPP and MISO standards. However, the improvements identified will need to be reviewed and approved by the MAPP Design Review Subcommittee (DRS) and therefore, until that approval is obtained, transmission upgrades cannot be built. There is also the potential that the forthcoming stability analyses may require additional system improvements beyond those initially identified by Xcel Energy Transmission in this report.

Appendix A – Idev File for New Generation and Interconnection Breaker Diagram

Appendix B – Existing System Maps and ACCC Results

Appendix C –Powerflow Results After Generation Addition, and Final Results after Infrastructure Improvements

Appendix D – Indicative Estimate

Appendix E – Constrained Interface Output