Xcel Energy

South Minneapolis Electric Reliability Study

Xcel Energy Services; Transmission System Planning and Reliability Assessment.

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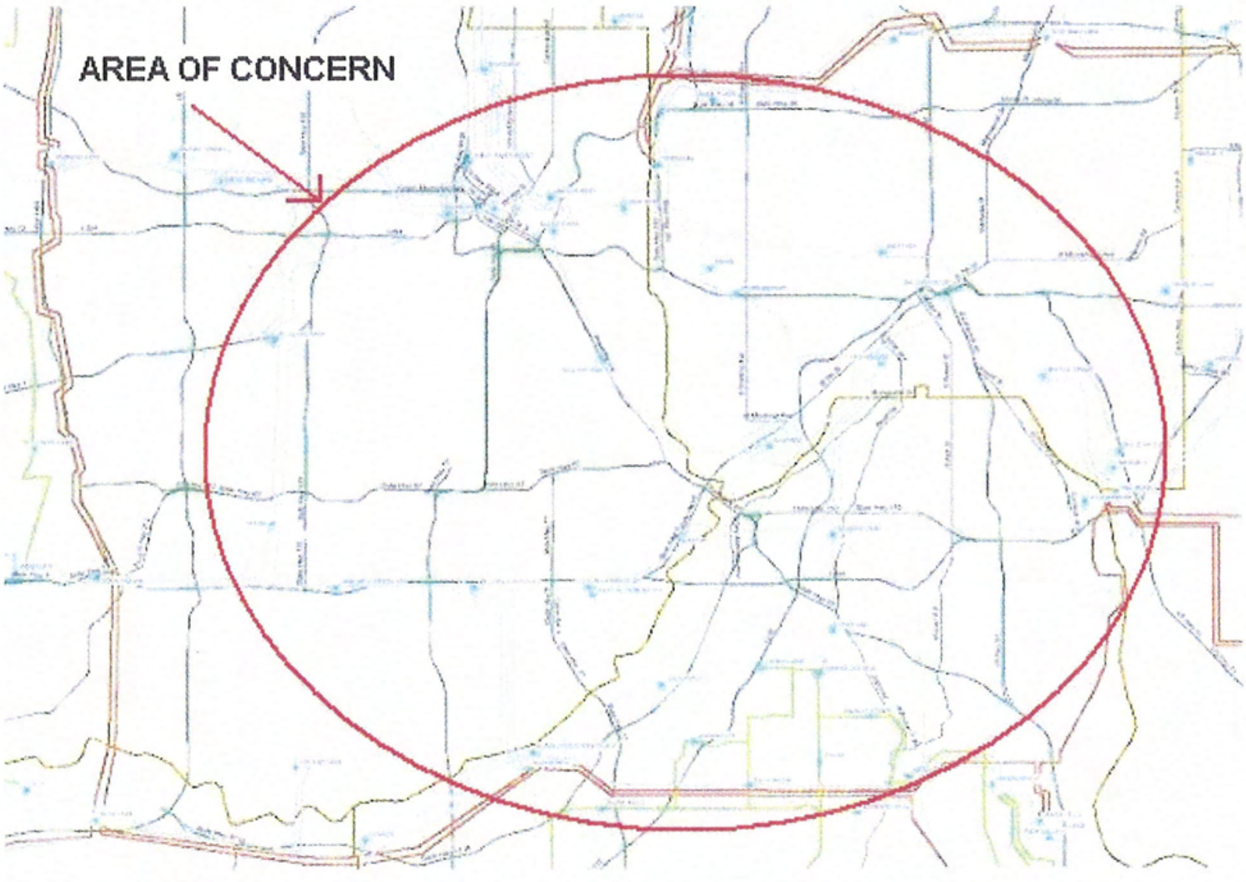
Contents.

1.0: Overview

This report represents the results of a long-range study for the electrical transmission network in the greater Minneapolis Metro area with a focus on the south Minneapolis area. This study reviewed the capability of the existing transmission system to serve the proposed new distribution substations to accommodate the projected Minneapolis metro load growth. The result of this analysis is a recommendation to build a new 345 kV line to serve the new distribution substations along with several new 115 kV lines to serve the projected load growth in the Minneapolis Metro area to the year 2028. This plan is expected to have an installed cost of $115,722,800.

1.1: Map



2.0: Conclusions & Recommended Plan

The Preferred Plan is the Hiawatha 345 Option, which adds the following facilities:

- In 2010 add a new Hiawatha 115 kV distribution substation on the Elliot Park-Southtown 115 kV line. A new Midtown 115 kV substation with a new double-circuit 115 kV line to the Hiawatha substation.

- In 2013 add a new Cleveland 345/115 kV substation that taps the 345 kV line from Terminal to Kohlman Lake. A new 115 kV line from the Cleveland to the Lexington substation. Upgrade the two 448 MVA transformers at Red Rock to two 672 MVA transformers.
- In 2014 add a new 115 kV Crosstown distribution substation and add a double-circuit 115 kV line to the Wilson substation. Upgrade the two 448 MVA transformers at Parkers Lake to two 672 MVA transformers. Upgrade the two 448 MVA transformers at Eden Prairie to two 672 MVA transformers.
- In 2016 add the second distribution transformers at Crosstown and Midtown.
- In 2017 add the second distribution transformer at Hiawatha.
- In 2018 reconductor the 115 kV line from Afton-Red Rock.
- In 2020, add a new 345 kV line from the Cleveland substation to the Hiawatha substation. Add a new 345/115 kV, 448 MVA transformer at Hiawatha.

This option appears to offer the best overall results with respect to:

- Power system performance (system intact & contingent loadings & voltages)
- Practicality (logistics of construction and operation)
- Price (cumulative present worth cost)
- Fit overall vision for the metro area
- System Losses
- Best option for serving the distribution load

It is noted that the distribution transformers are not considered a transmission cost, but the costs were applied equally to every option studied. So the net effect of removing them would be the same for all the options.

3.0: Study History & Participants

Xcel Energy technical staff and consultants performed the powerflow simulations, economic analyses, and tabulation of results. These results were presented and reviewed at the study group's meetings, at which comments, conclusions, and recommendations were developed to guide each successive stage of analysis.

This study was presented at the July 24th, 2008 SPG meeting held at Great River Energy's Offices.

4.0: Introduction

4.1: System Description

The Twin Cities metropolitan area is served by a 115 kV transmission system within a 345 kV double circuit loop. Most of the Twin Cities generation is connected to this 345 kV loop except the High Bridge and Riverside combustion turbines. For this analysis, before the year 2018 all Twin Cities generation was assumed on during system peak. The post 2018 cases were developed to accommodate a 30% wind penetration on the system. In order to accommodate this local Twin Cities generation was turned down. This will put extra strain on the existing 345/115 kV transformers along the 345 kV loop as internal generation is turned down.

Load projections from distribution planning has determined a need for addition load serving support in the south Minneapolis Metro area to meet the expected load growth. This new load growth along with the continued load growth for the entire metro area will increase the burden on the existing transmission system, causing several transmission overloads under contingency.

4.2: Scope of Study

The purpose of this study is to examine a 10-year planning horizon to identify transmission system deficiencies and propose solutions to alleviate these issues. Steady-state powerflow cases are run to determine if the transmission system is capable of handling the subsequent load associated with the new interconnection request during normal and contingent system operation. Dynamic simulations are run to determine how the interconnections and upgrades impact the transmission systems dynamic performance under contingencies.

5.0: Planning Criteria

Steady-State Criteria

A summary of Xcel Energy's steady state planning criteria is shown in Table 1.

Table 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	115% post-contingency if pre-contingency loading is below 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.

In addition to adhering to these planning criteria, we meet all the guidelines outlined for the TPL planning standards as defined by NERC.

Dynamic Criteria

A summary of Xcel Energy's dynamic planning criteria is shown in Table 2.

Table 2 – Dynamic Stability Criteria

NERC Categories	Transient Voltage Deviation Limits	Rotor Angle Oscillation Damping Ratio Limits
A	Nothing in addition to NERC Requirements	
B	Minimum 0.70 p.u. at any bus	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips.
C	Minimum 0.70 p.u. at any bus	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips.
D	Nothing in addition to NERC Requirements	

5.1: Models Employed

5.1.1: Steady State Models

The powerflow models employed were developed by the MRO model building group. The models are based on the 2007 Series MRO models, Year 2012 summer peak and a modified 2018 summer peak model as updated:

- to reflect system changes by appropriate study year.
- to reflect the Post CAPX2020 Group 1 facilities by appropriate study year (2018).
- to reflect 30% wind penetration for a specific 2018 case.

5.1.2: Dynamics models

There were no dynamic stability runs done with this study.

5.2: Conditions Studied

5.2.1: Steady State Modeling Assumptions

The technical analysis was performed based upon year 2012 and 2018 summer peak cases from the 2007 MRO series powerflow models. The base models were adjusted to represent the latest available forecast data for summer season peak (100%) load conditions. The 2018 30% wind penetration case simulates 30% renewable generation transferred to the Twin Cities.

Table 3

					Net generation, MW				
Condition	load level	NDEX[1]	MHEX[2]	MWEX[3]	Wind	Blue Lake	Black Dog	High Bridge	River Side
Peak	100 %	497.0	555.7	399.0	1014	497	588	610	563
30% Case	100 %	1044.6	472.8	535.2	3600	0	352	610	314
NMORWG Limit:		2080	2175	1480					

Notes
1) NDEX= sum of flows on the 18 lines comprising the "North Dakota Export" Boundary;
2) MHEX = sum of flows on the 4 Manitoba Hydro-U.S. 230 & 500 kV tie lines;
3) MWEX = sum of flows on Minnesota-Wisconsin Export (King- Eau Claire 345 kV, phase shifter on Arrowhead-Weston 345 kV) This interface was in the process of being reevaluated to include the Arrowhead-Weston 345 kV line during this study.

5.2.2: Performance Evaluation Methods

Power system performance simulation was performed with the aid of the MUST (Managing and Utilizing System Transmission) digital computer powerflow program (Version 8.3) as supplied by Power Technologies, Inc. System intact and first-contingency analysis was performed primarily using PSS-MUST (Version 8.3) activities ACCC and TLTG ("Transfer Limit Table Generator"). TLTG performs automated contingency analysis while progressively incrementing power transfer between a defined "source" and "sink" location.

For both the ACCC and the TLTG analysis, the following apply:

Monitored facilities:
All transmission lines and transformers 69 kV and above in the model areas:
NSP (Xcel) GRE

Study area (facilities subject to outage):
All transmission lines and transformers 69 kV and above in the model zones:
NSP (Xcel) GRE

Activity TLTG achieves computational efficiency by extensive use of Power Transfer Distribution Factors (PTDFs) and Line Outage Distribution Factors (LODFs), concepts applicable to linear, time-invariant systems. These methods are appropriate for power system analysis, provided it is recognized their accuracy is constrained by their inherent limitations arising from non-linear effects such as exhaustion of reactive power supply and LTC transformer range limits. Consequently, the resultant reported transfer limits from TLTG are thus approximate.

Facilities identified in the TLTG outputs are considered valid limiters if they…

have a PTDF of 5.0% or greater (system intact) or
have an OTDF of 3.0% or greater (outage condition).

This 5.0% criterion was selected in accordance with the MISO's cutoff level for system impact analyses. Very large reductions in generation (over 50:1) are required in order to achieve a perceptible amount of loading relief. Consequently, PTDFs/OTDFs lower than 5% strongly indicate that other power system adjustments are likely to be much more effective in producing the desired ameliorative effect than would generation adjustments in the study area. Refer to Section 5.2 for further discussion on evaluation of incremental loadings on constrained interfaces ("flowgates") and non-flowgate facilities.

5.2.3: Steady State Contingencies modeled

For this study we included all N-1 and tie line contingencies for the Xcel and GRE areas. In addition, we ran all the Category C contingencies listed in the UPDATE-2-7 w stk bkrs.con file.

Key area system deficiencies and contingencies:

Base Case Issue	Contingency	Year
Goose Lake-Vadnais Hgts 115 kV	Apache Tp-Arden Hills 115 kV	2012-2014
Lexington-Vadnais Hgts 115 kV	Apache Tp-Arden Hills 115 kV	2012-2014
Apache Tp-Arden Hills 115 kV	Goose Lake Dbl Ckt	2012-2014
Coon Creek 345/115 xfmrs	Eden Prairie STK breaker	2018
Cedervale-Southtown 115 kV	Coon Creek STK breaker	2020
High Bridge-Sheppard 115 kV	Elliot Park STK breaker	2021
Terminal 345/115 xfmrs	Elliot Park STK breaker	2021
Eliot Park-Mainstreet 115 kV	Shepard-Southtown DBL Ckt	2022
Elliot Park-Hiawatha 115 kV	Shepard-Southtown DBL Ckt	2020
Parkers Lk-Basset Creek 115 kV	Terminal STK breaker	2022

Relevant contingencies are provided in Appendix C.

5.3: Options (Plans) Evaluated

Several distribution options we evaluated to see if they provided any advantage over the transmission options. Loss analysis and present worth analysis were used to determine the best location of the Midtown substation. The following distribution improvement options were evaluated:

DO1 "East Distribution Site"

This option has the Hiawatha substation tapping the existing 115 kV line from Elliot Park-Southtown. Adding 2-115 kV lines from Hiawatha to the new Midtown substation located east of the Sears Building.

DO2 "West Distribution Site"

This option has the Hiawatha substation tapping the existing 115 kV line from Elliot Park-Southtown. Adding 2-115 kV lines from Hiawatha to the new Midtown substation located west of I-35W.

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DO3 "6-Bank Hiawatha (Super Hiawatha)"

This option has the Hiawatha substation tapping the existing 115 kV line from Elliot Park-Southtown. There is no Midtown substation assumed for this option. Instead 6 conductor lines will be served from 3 115/13.8 kV transformers located at Hiawatha.

DO4 "Hiawatha-Midtown 34.5 kV underground"

This option has the Hiawatha substation tapping the existing 115 kV line from Elliot Park-Southtown. Adding 2-34.5 kV underground lines from Hiawatha to the Midtown substation located east of the Sears Building.

The following transmission improvement options were evaluated:

Option 1 "115 kV dbl ckt, dbl bundled Hiawatha Plan"

This option establishes a new 345/115 kV Cleveland substation that taps the existing 345 kV line from Coon Creek-Kohlman Lake. Build a new double circuited, double bundled 115 kV line from Cleveland to the new Hiawatha substation. Build a new double circuited 115 kV line from the Hiawatha substation to a new Midtown substation.

Option 2 "345 kV Hiawatha Plan"

This option establishes a new 345/115 kV Cleveland substation that taps the existing 345 kV line from Coon Creek-Kohlman Lake. Build a new 345 kV line from the Cleveland substation to a new Hiawatha substation. Build a new double circuited 115 kV line from the Hiawatha substation to a new Midtown substation.

Option 3 "Parkers Lake-Aldrich 345 kV Plan"

This option establishes a new 345 kV line from Parkers Lake to Aldrich. Build a new 115 kV line from Aldrich to a new Midtown substation. Build a double circuited 115 kV line from Midtown to Hiawatha.

Option 4 "Quad 345 kV Plan"

This option establishes a new 345/115 kV Cleveland substation that taps the existing 345 kV line from Coon Creek-Kohlman Lake. Build a new 345 kV line from the Cleveland substation to a new Hiawatha substation. Build a new double circuited 115 kV line from the Hiawatha substation to a new Midtown substation. Build a new 345 kV line from Parkers Lake to Aldrich. Build a new 345 kV line from Red Rock-Rodgers Lake. Add a new 345 kV bus section and transformer at the existing Black Dog substation.

These options all address the immediate load serving needs of the South Minneapolis area and take into consideration future load serving needs of the whole area.

6.0: Results of Detailed Analysis

6.1: Losses: Technical and Economic Evaluation

Losses are power that dissipates in electric conductors due to a materials resistance. The amount of loss is greatly reduced by lowering the current flowing through a line. For the Xcel Energy 10 Year plan losses were evaluated during projects to show system benefits. The cost of purchasing generation at marginal prices for capacity and energy were evaluated. This savings was factored into the economic analysis.

To develop the savings associated with reducing losses an evaluation technique was developed. Ten transformers were studied throughout the Twin Cities. Transformer load was taken at peak conditions and then an average loading was gathered. This information was used to develop a load duration curve. The MRO models use a 10% coincidence factor, which means loads appear 10% less than their transformer peak. This coincidence factor is shown in the calculations. Table 6.1 shows the calculations used to create a loading factor. Equation 6.1 details how the Load Factor (LF_1) was calculated.

$$\text{Equation 6.1: } LF = \frac{TRavg}{0.9 * TR\max}$$

Transformer	TR avg	TR Max	Load factor
TR#1	22	44	0.56
TR#2	30.56	51.73	0.66
TR#3	8.44	20.08	0.47
TR#4	11.33	21.04	0.6
TR#5	33.65	63.39	0.59
TR#6	8.85	20.24	0.49
TR#7	21.35	41.83	0.57
TR#8	6.33	19.77	0.36
TR#9	21.4	45.39	0.52
TR#10	30.22	56.11	0.6
		Average Load Factor	0.54

Table 6.1 Load Factor Development

To calculate the Loss Factor (LF_2) the following equations detail the methodology. Equation 6.3 details the correlation between load and current. As the load increases the loading on the

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